Tom Brown, Inc. 2001 Annual Report

CAN UPSTREAM NATURAL GAS GROWTH COMPANY

In 2001, Tom Brown achieved a 21% growth

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in reserves and a 23% increase in production.

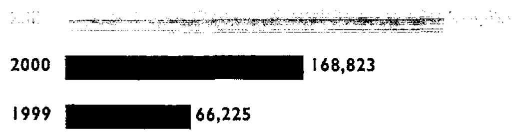
Tom Brown, Inc. is a Denver, Colorado based independent energy company engaged in the exploration for, and the development, acquisition, production and marketing of natural gas, natural gas liquids and crude oil primarily in the gas prone basins of the North American Rocky Mountains and Texas. The Company maintains a dominant land position in its core operating areas, with over 2.3 million net acres, 85% of which are undeveloped.

At year-end 2001, the Company's proved reserves totaled 732 billion cubic feet equivalent, representing a 21% increase over 2000. The year-end 2001 proved reserves are 88% natural gas and 86% of the reserves are from fields located in the U.S. and Canadian Rockies. Net daily production in 2001 averaged 209.3 Mmcfe, increasing 23% over 2000. Tom Brown has achieved compound annual growth in production of 22% over the last three years.

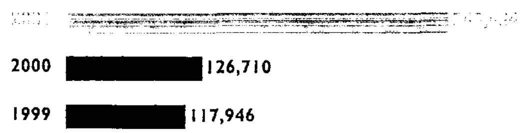
Tom Brown trades on the NASDAQ National Market under the symbol TMBR.

FINANCIAL HIGHLIGHTS

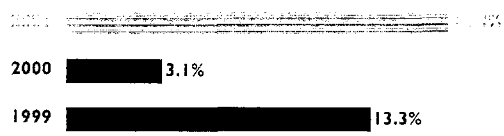
CASH FLOW [in thousands]



CAPITAL EXPENDITURES



NET DEBT / TOTAL BOOK CAP.



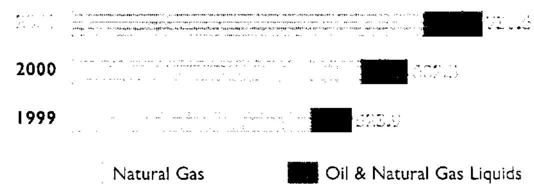
Tom Brown achieved
reserves, cash flow
The Company made
in 2001, positioning

THREE-YEAR FINANCIAL SUMMARY

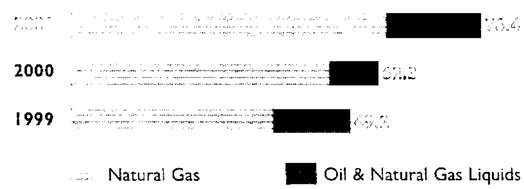
(Thousands except per share amounts)	2001	2000	1999
TOTAL REVENUES	$326,324	$253,910	$123,411
NET INCOME	$ 69,503	$ 66,578	$ 6,757
PREFERRED STOCK DIVIDENDS	$ –	$ (875)	$ (1,750)
NET INCOME APPLICABLE TO COMMON STOCK	$ 69,503	$ 65,703	$ 5,007
PER SHARE, DILUTED	$ 1.73	$ 1.76	$ 0.15
DISCRETIONARY CASH FLOW FROM OPERATIONS	$218,627	$168,823	$ 66,225
PER SHARE	$ 5.43	$ 4.48	$ 2.04
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING, DILUTED	40,227	37,897	32,466
TOTAL EXPLORATION AND PRODUCTION CAPITAL EXPENDITURES	$340,454	$126,710	$117,946
TOTAL ASSETS	$844,975	$629,535	$536,299
WORKING CAPITAL	$ 11,278	$ 38,139	$ 19,357
PROPERTY AND EQUIPMENT, NET	$972,660	$509,762	$431,803
LONG-TERM DEBT	$120,570	$ 54,000	$ 81,000
SHAREHOLDERS' EQUITY	$575,228	$488,893	$402,097

record production,
and earnings in 2001.
significant investments
it for the future.

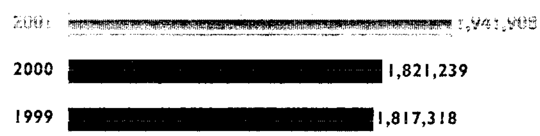
PROVED RESERVES [BCFE]



PRODUCTION [BCFE]



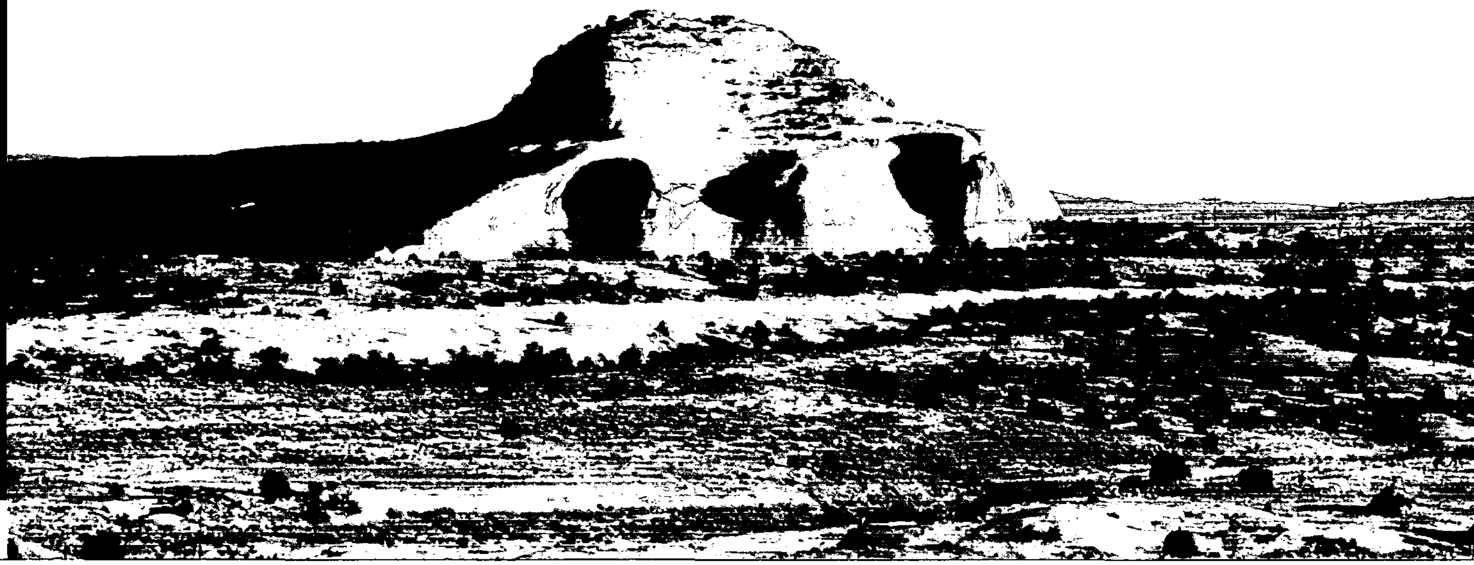
NET UNDEVELOPED ACRES



THREE-YEAR OPERATIONS SUMMARY

	2001	2000	1999
YEAR-END RESERVES:			
NATURAL GAS (Mmcf)	641,579	535,373	445,933
OIL AND NATURAL GAS LIQUIDS (MBbl)	15,007	11,193	13,001
TOTAL EQUIVALENT (Mmcfe)	731,621	602,531	523,939
SEC PV-10, DISCOUNTED AT 10% PRE-TAX	$501,288	$2,187,925	$393,423
PRODUCTION:			
NATURAL GAS (Mmcf)	63,824	51,199	40,514
NATURAL GAS LIQUIDS (MBbl)	1,217	1,074	536
OIL (MBbl)	881	773	909
TOTAL EQUIVALENT (Mmcfe)	76,412	62,282	49,182
AVERAGE SALES PRICE:			
NATURAL GAS ($/Mcf)	$ 3.71	$ 3.46	$ 2.04
NATURAL GAS LIQUIDS ($/Bbl)	14.07	16.77	12.16
OIL ($/Bbl)	23.09	28.05	16.98
TOTAL EQUIVALENT ($/Mcfe)	3.59	3.48	2.12
UNDEVELOPED ACREAGE:			
GROSS	2,892,365	2,665,490	2,612,648
NET	1,941,908	1,821,239	1,817,318

Tom Brown is a leading E&P company



Dear Fellow Shareholders:

Natural gas is the most efficient and clean-burning fossil fuel currently available to our country. With an ample domestic resource "potentially" available for development, natural gas is the ideal fuel to meet our nation's growing energy needs. Everyone agrees that our energy needs are growing. Ironically, it may be the only issue regarding energy that everyone seems to agree on.

The natural gas industry has just emerged from two of the most volatile years in the history of our business. Whether our government, media or the general public decides to focus on it or not, our country has entered into a very tight supply and demand balance for natural gas. The U.S. produced approximately 12% less gas in 2000 than in 1973. Without growing imports of natural gas from our Canadian neighbors the supply and demand situation in this country would already be untenable. While the much talked about "gas bubble" of excess supply existed from the early 1970's until only recently, the production response from last year's frenetic drilling activity was sobering and should be difficult for anyone to ignore. Literally, the domestic industry ran as fast as it could, averaging 939 rigs drilling for natural gas in 2001, but achieved little, if any, volume growth. At the writing of this letter, there are only 610 rigs drilling for natural gas in the U.S. Due to increasing decline rates on our nation's production base and last year's weak production response, many observers predict that natural gas prices will rise and become even more volatile in the future.

So what is hindering our industry from providing the necessary growth in supply? Inadequate and volatile gas prices, lack of public land access, excessive regulatory hurdles and serious infrastructure constraints including drilling and completion equipment, gathering and transportation pipe, and people top the list. These issues are extremely important and they all need to be discussed and addressed at industry, county, state and federal levels. However, an often-overlooked, critical component of the entire situation is the woefully inadequate level of exploration taking place within our country. It appears that many companies don't have the people, acreage, ideas or consistent corporate fortitude to explore. The industry has done an outstanding job of exploiting existing producing assets, and these activities have provided much of our gas supply over the last ten years. But at some point exploitation growth hits the wall. It's a finite game. There are only two ways to bring new fields ripe for exploitation into one's organization. You either need to find them or buy them. Many exploration and production (E&P) companies acquire reserves to achieve their growth; some proceed to exploit these assets very effectively and others do not. Either way, acquisitions are widely perceived as a guaranteed low-risk method of achieving production growth, a perception which will continue to fuel the rapid industry consolidation that has taken place over the last several years. However, simply acquiring and exploiting will not satisfy our country's energy needs; we HAVE to explore. Many consider 1986 to represent the depths of the modern oil and gas industry's depression. Hundreds of thousands of employees left the industry, oil and gas prices were low and the future looked bleak. Yet, according to the

supplying a growing volume of natural gas.

American Petroleum Institute, in 1986 the industry drilled a total of 7,156 exploratory wells in the U.S. Comparatively, the year 2000 was a period of rising expectations for the future with greatly increased drilling and leasing activity over previous years and higher oil and gas prices that rose steadily throughout the year. Amazingly, the industry drilled only 2,076 exploration wells in 2000, less than one third of the exploration effort in 1986. In other words, the country's exploration exposure has been and continues to be anemic. This situation has to change.

Tom Brown is very proud to be one of the leading independent E&P companies consistently supplying a growing volume of natural gas to the market. Due to the teamwork, dedication and technical excellence of our employees, the Company achieved record production, reserves, cash flow and net income in 2001. Our strong efforts to diversify our exposure within the prolific natural gas basins of the Rocky Mountains and Texas provided much of last year's impressive results. The Rocky Mountain area possesses the second largest resource of natural gas in North America behind the Gulf of Mexico, and most of this resource base has yet to be exploited. The National Petroleum Council estimates that 85% or 300 Tcf remains untapped in the Rockies. Tom Brown's long-term commitment to the Rockies was and remains both visionary and timely. The Company now has six major core areas that bring a heretofore unseen balance and diversity to our drilling and investment portfolio. None of this would happen without talented people. We are extremely proud of the quality, experience and business acumen of our employees and it is exciting to witness the constant creation of new opportunities by our teams.

Tom Brown will continue to maintain a strong balance sheet. At year-end 2001, net debt to total capitalization ratio totaled 16%. This conservative approach to leverage gives Tom Brown considerable flexibility to capture additional opportunities in the future. Our fundamental belief is that a company needs a healthy balance of acquisitions, development and exploratory drilling projects to achieve consistent long-term success. To achieve this balance Tom Brown has assembled an immense, highly prospective acreage position, a robust exploration and development portfolio and technically advanced acquisition, exploitation and prospect generating teams. These tremendous assets, coupled with a consistent corporate commitment to explore, position Tom Brown to be one of the leading independent E&P companies for many years to come. We are proud to be a part of the nation's energy solution and will always remain focused on creating long-term value for our shareholders.

Thank you for your continued trust and support.

James D. Lightner
President and Chief Executive Officer

James B. Wallace
Chairman of the Board of Directors

The nation's challenge to grow natural gas

What a difference a year can make in energy prices. In 2000 rising prices appeared to indicate a looming energy crisis for our country. Spot natural gas prices at Henry Hub in Louisiana began climbing in the second half of 2000 and peaked during December of that year at $10.50/MMBtu. Natural gas prices decreased throughout 2001 from a high of $10.20/MMBtu during January to a low of $1.74/MMBtu during November.

Many dynamics contributed to the significant decrease in natural gas prices throughout 2001. However, the most significant factors appear to revolve around reduced demand, including decreased industrial consumption and fuel switching, mild winter weather and a slowing economy.

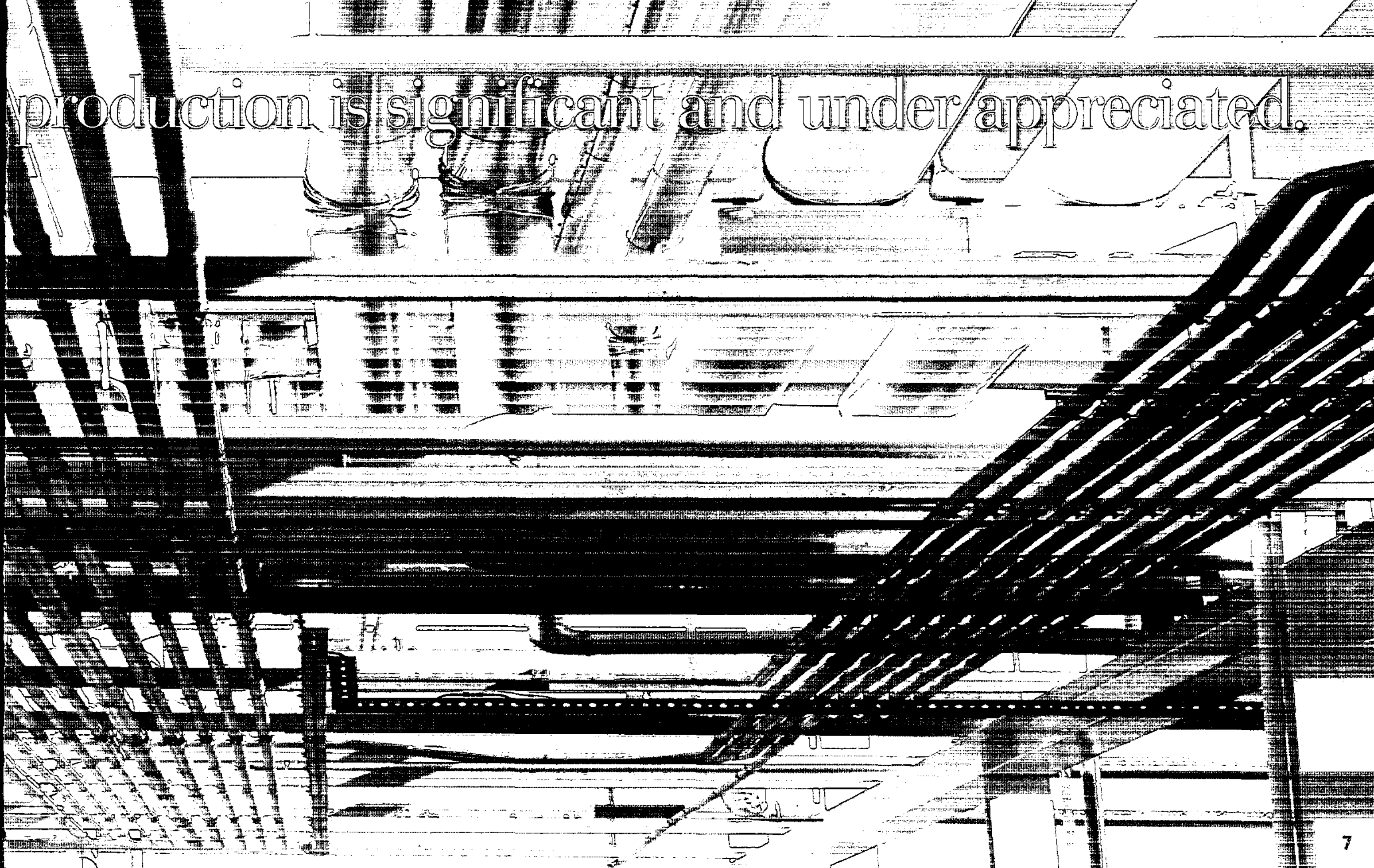
In the industrial segment, free market dynamics responded quickly to higher natural gas prices in the early part of 2001 by either shutting down facilities or switching to alternative less expensive fuels. The Energy Information Administration (EIA) consumption statistics indicate a 5% or 1.2 Bcf/d decrease in industrial demand for natural gas from 2000 to 2001.

Weather also has played a significant factor. In December 2001, according to the EIA, temperatures (on a gas customer-weighted heating degree days basis) averaged 29% warmer than the corresponding period of 2000 and 16% warmer than normal. The warmer weather resulted in a 33% decrease in residential natural gas consumption or nearly 10 Bcf/d in December 2001 as compared to 2000.

In total, the EIA estimates that the daily gas consumption for 2001 average 59.1 Bcf/d which is 2.5 Bcf/d or 4% less than 2000. The significant drop in natural gas consumption juxtaposed against a slightly rising supply in the first half of 2001 resulted in the major drop in prices during the year.

The E&P industry reacted to the higher natural gas prices in early 2001 by significantly increasing activity levels as indicated by the rig count. The average number of rigs drilling for natural gas in 2001 increased 30% over 2000. In fact, the 2001 average number of rigs drilling for natural gas of 939 is nearly double the annual average over the ten-years prior to 2000. With the ramp up in activity in the first half of 2001, the U.S. E&P and service industries essentially reached maximum capacity. The rig count peaked in mid-2001 and has since steadily declined.

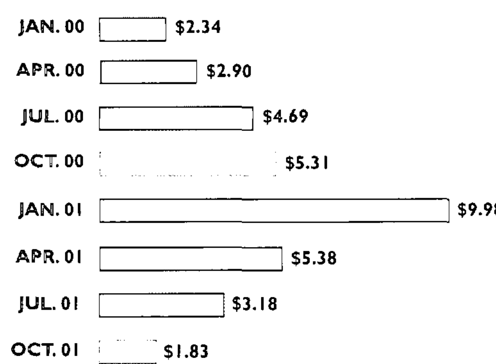
production is significant and under/appreciated.



The tremendously high level of drilling activity would logically translate into higher natural gas production levels. However, the impact on supply of natural gas appears to be relatively muted. The EIA is currently estimating that natural gas production in the United States only managed to grow slightly more than one Bcf/d from 2000 to 2001. The EIA estimates would indicate a 1.9% increase in production. This appears to be high relative to other industry observers who, based upon a survey of public companies' production levels, believe the actual production change in 2001 could be somewhere between a 0.5% decline to a 1% gain. Either way, the conclusion is the same. The nation's challenge to grow natural gas production is significant and under appreciated.

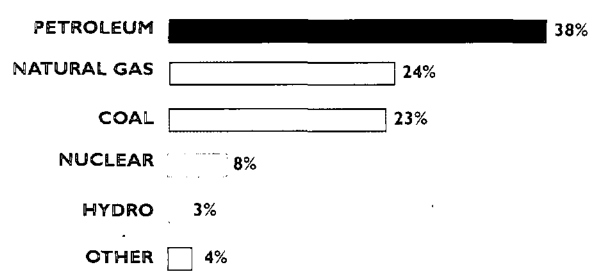
Tom Brown continues to believe in the long-term fundamentals of natural gas and the critical role natural gas will play in meeting the country's energy needs as a clean burning environmentally friendly fuel. Tom Brown has in the past and will continue to maintain a disciplined strategy of exploring for, developing, producing and acquiring natural gas in its core areas of the Rocky Mountains and Texas. The Company will, however, monitor the macro gas environment and adjust the timing and mix of these activities based on natural gas prices.

HENRY HUB SPOT NATURAL GAS PRICE* [$/MMBtu]



* end of month closing price

U.S. ENERGY CONSUMPTION



Our deep development portfolio allows flexibility to

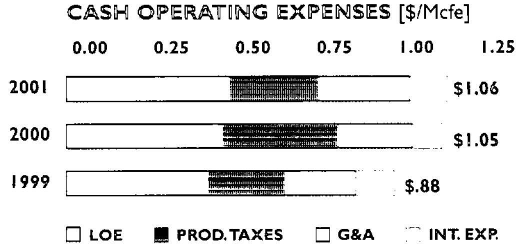
Tom Brown's geographic areas of focus are concentrated in the gas prone basins of the U.S. and Canadian Rocky Mountains and East and West Texas. Within its core areas the Company maintains a large acreage position of undeveloped land creating opportunity for future exploration and development activities.

Tom Brown had an outstanding year in 2001, achieving record levels of production, reserves, cash flow and earnings. Additionally, we completed an acquisition of a Canadian company providing a platform for growth in the Canadian Rockies. The Company also made significant investments which will benefit future years including plant expansions, exploration seismic and drilling and land acquisitions.

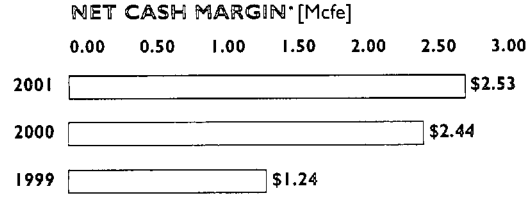
Operationally, Tom Brown had an extremely active year drilling 200 gross wells in 2001, which is more than double the wells drilled in 2000. Tom Brown's deep portfolio of development opportunities allows the Company the flexibility to ramp up activity when the price environment warrants. Tom Brown as a result of the greater drilling activity grew its U.S. natural gas production by 12% in 2001 over 2000.

ramp up activity as the price environment warrants:

CASH OPERATING EXPENSES [$/Mcfe]

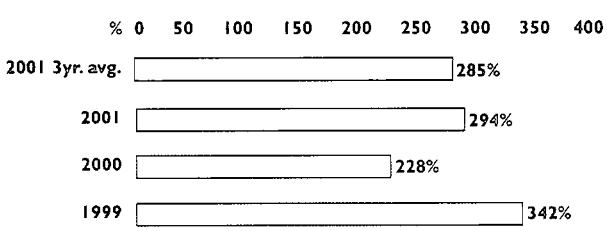


NET CASH MARGIN* [Mcfe]

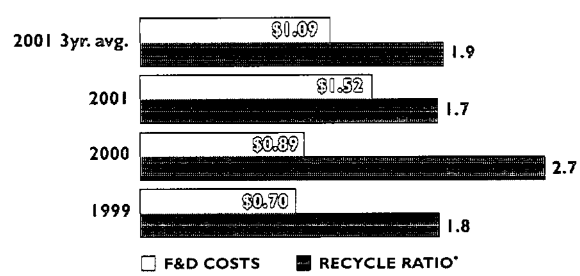


* Oil & Gas sales less cash cost lease operating expense, production taxes, general and administrative expense, and interest expense

ALL-SOURCES RESERVE REPLACEMENT

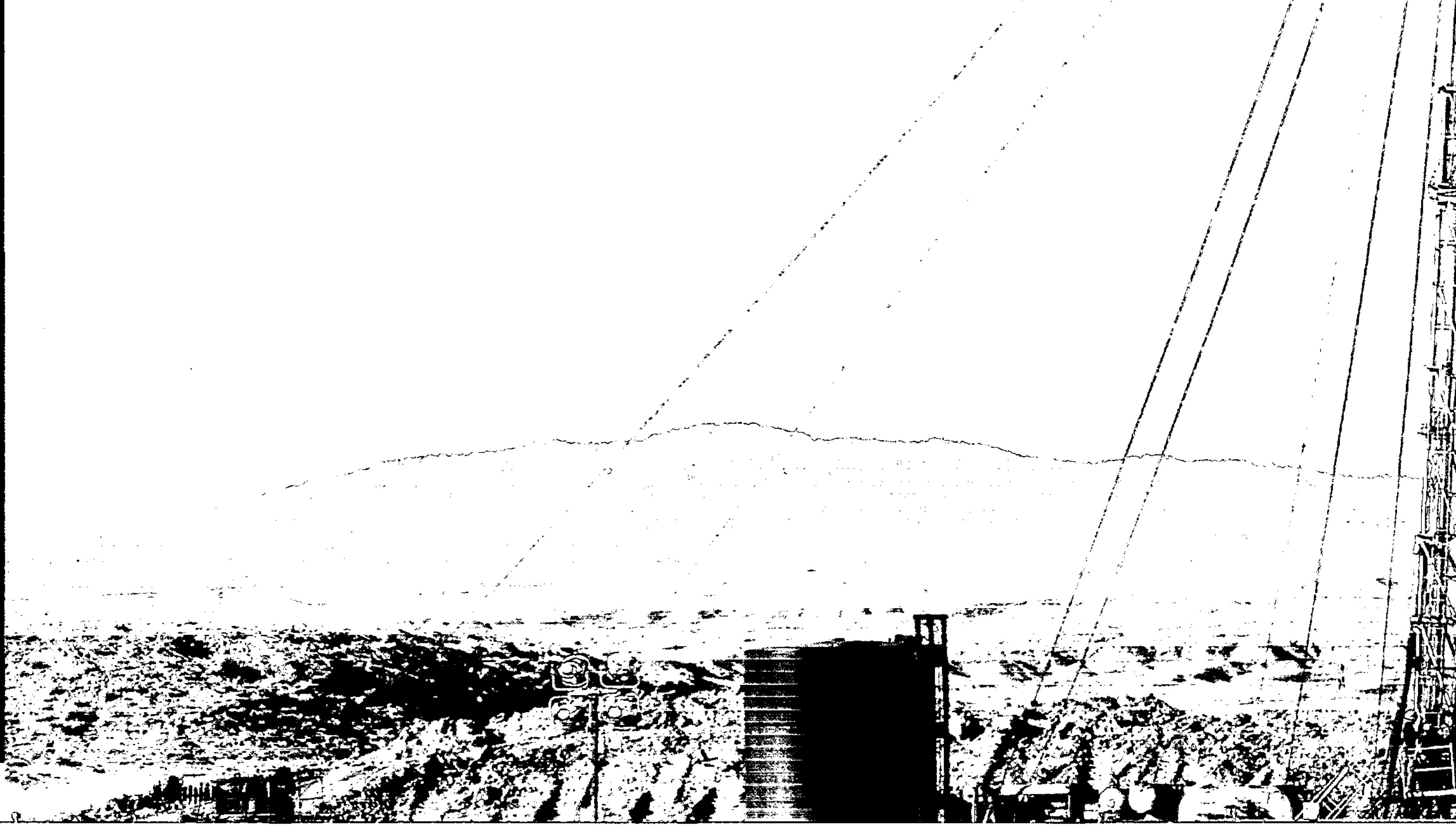


ALL-SOURCES FINDING AND DEVELOPMENT COSTS (F&D) [$/Mcfe]



* Recycle ratio = F&D Cost/Net Cash Margin

The Wind River Basin remains one of our core



WIND RIVER BASIN

The Company's Wind River Basin (WRB) operations are primarily conducted in the Pavillion, Muddy Ridge, and Frenchie Draw fields. Both the Pavillion and Muddy Ridge fields are located on the Northern Arapaho and Eastern Shoshone Indian reservation. The WRB represents 27% of the Company's year-end 2001 proved reserves and 24% of its 2001 production.

The majority of Tom Brown's 2001 drilling activity in the WRB occurred in the Pavillion field where 38 out of 39 successful wells were drilled in 2001. In total in the WRB for 2001, the Company drilled 59 wells and at year-end 50 were completed, five were in the process of being completed and four were plugged and abandoned.

The wells drilled at the Pavillion field and completed in the Upper Wind River formation had an average initial gross production rate of 1.2 Mmcfpd. As a result of the strong drilling results in the Pavillion field, the Company in 2001 grew its net production from the Wind River Basin by 16% over 2000, producing on average 49.2 Mmcfped for the twelve months ended December 31, 2001.

WIND RIVER BASIN

	2001	2000	1999
PRODUCTION [Mmcfepd]	49.2	42.3	30.7
TOTAL GROSS ACREAGE [in thousands]	582	970	1,079
TOTAL NET ACREAGE [in thousands]	412	761	852
E&P CAPITAL SPENDING [$s in MM]	$61.2	$42.9	$28.2
LEASE OPERATING EXPENSE [per Mcfe]	$0.17	$0.19	$0.12

areas, achieving 16% production growth in 2001.

GREATER GREEN RIVER BASIN

The Greater Green River Basin (GGRB) made up 12% of both Tom Brown's year-end 2001 proved reserves and 2001 production. The Company drilled or participated in 16 wells in the GGRB of which 11 were successful.

As a result of the successful development drilling program the Company's GGRB 2001 production grew by five percent over 2001. However, within the GGRB Tom Brown's major focus is on exploration. The Company controls over 166,000 net undeveloped acres in the GGRB on which the Company plans to continue exploring for large basin-centered gas accumulations.

PICEANCE BASIN

The Piceance Basin made a significant contribution in 2001 to Tom Brown's reserve and production growth, primarily as a result of the successful *coal bed methane development project* at its White River Dome field. In 2001, this Basin accounted for 21% of the Company's year-end proved reserves and 11% of 2001 production.

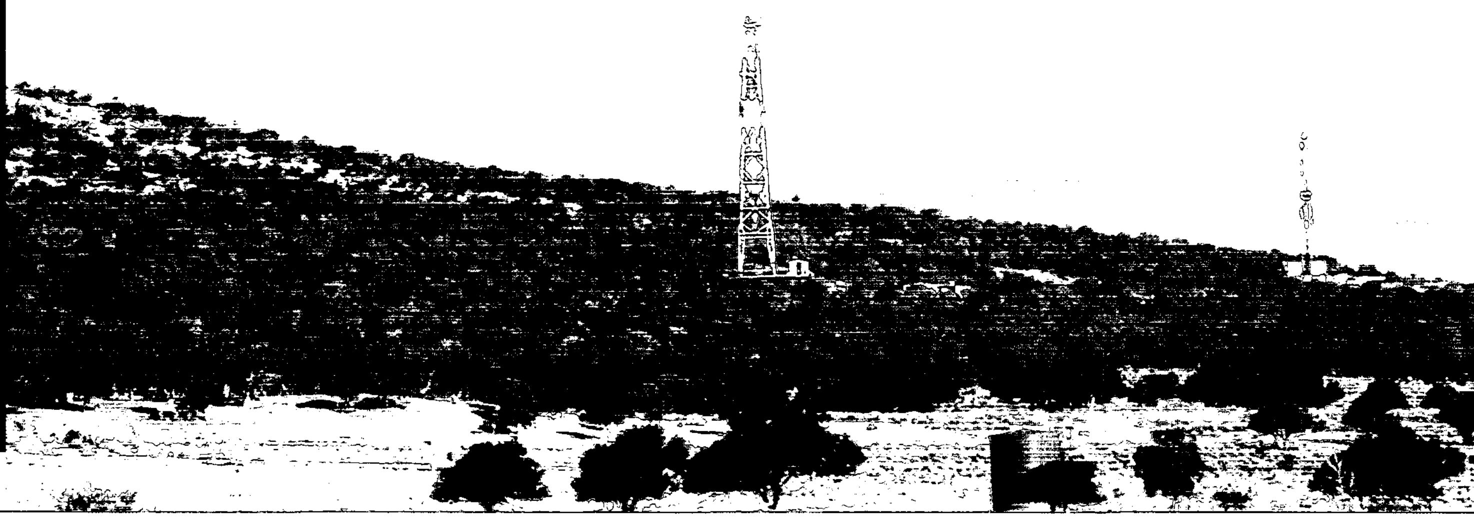
Tom Brown drilled 43 wells in the Piceance Basin in 2001 achieving a 100% success rate. The majority of the 2001 drilling centered on the White River Dome (WRD) and the Parachute/Grand Valley areas where 27 and 10 wells were drilled, respectively.

The Company's highly successful drilling program in the Piceance Basin resulted in production growth of 23% in 2001 over 2000 and 38% in the

GREATER GREEN RIVER BASIN

	2001	2000	1999
PRODUCTION [Mmcfepd]	25.2	24.0	17.9
TOTAL GROSS ACREAGE [in thousands]	394	441	443
TOTAL NET ACREAGE [in thousands]	248	292	296
E&P CAPITAL SPENDING [$s in MM]	$15.0	$16.8	$9.1
LEASE OPERATING EXPENSE [per Mcfe]	$0.39	$0.35	$0.39

Tom Brown grew production 71% in 2001 in



fourth quarter of 2001 over the third quarter of 2001. The increase in production is primarily a result of the active drilling program at the WRD and the October startup of a new processing plant.

Production from the field throughout 2001 had been limited because of infrastructure constraints. Tom Brown contracted to have a new plant installed, which commenced operations in October 2001. Initially, the plant inlet capacity was limited by the installed compression to 14 Mmcfpd. Due to continued positive production performance, the Company had the plant expanded in February 2002, bringing the plant inlet capacity to 27 Mmcfpd and the total capacity in the field to 33 Mmcfpd.

Tom Brown drilled a total of 27 successful wells in 2001 at WRD, 24 had been completed and three were waiting to be completed at year-end 2001. Initial wellhead production rates have averaged 1.2 Mmcfd.

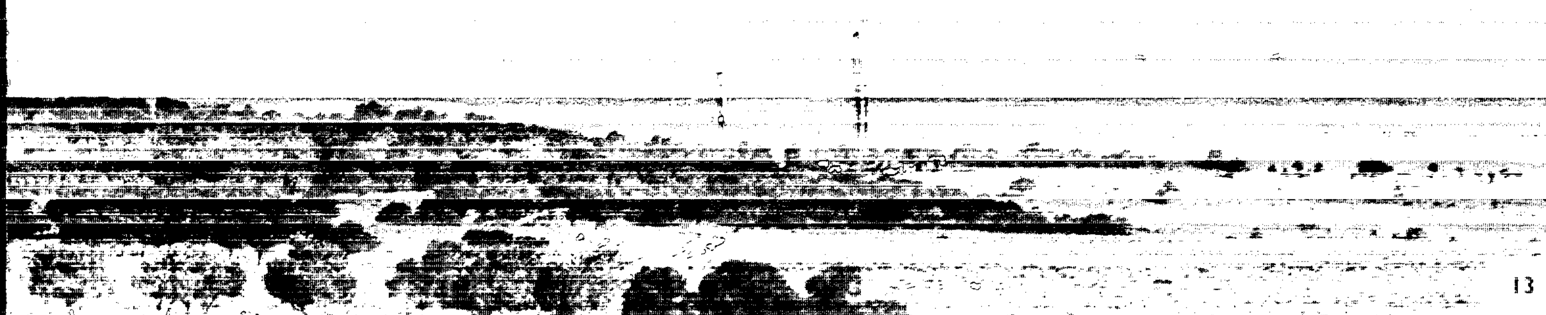
PICEANCE BASIN

	2001	2000	1999
PRODUCTION [Mmcfepd]	23.8	19.4	16.9
TOTAL GROSS ACREAGE [in thousands]	364	457	355
TOTAL NET ACREAGE [in thousands]	300	337	285
E&P CAPITAL SPENDING [$s in MM]	$43.7	$14.0	$4.1
LEASE OPERATING EXPENSE [per Mcfe]	$0.39	$0.42	$0.49

PARADOX BASIN

The Paradox Basin made up 15% and 19% of Tom Brown's year-end 2001 proved reserves and 2001 production, respectively. Tom Brown has a dominant position in the Paradox Basin controlling 322,000 net acres and a modern cryogenic gas processing plant. The Lisbon plant is the only facility in the Paradox Basin equipped to handle all gas stream contaminants, which gives Tom Brown significant leverage to participate in outside opportunities in the basin.

the White River Dome coal bed methane play.



The Company drilled or participated in eight wells in the Paradox Basin during 2001 of which six were successful. The Company grew its Paradox Basin production in 2001 over the prior year by 16%. The drilling activity primarily occurred at the Company's Andy's Mesa field where five productive wells were completed. The Company installed a new processing plant, which went into service in October 2001. The new processing plant allows Tom Brown to meet the pipeline specifications to access the Trans-Colorado pipeline. Initial production rates of the wells completed at Andy's Mesa have averaged 2.5 Mmcfpd gross. Tom Brown increased gross production rates from Andy's Mesa field from 1.5 Mmcfpd in early 2000 to over 19.5 Mmcfpd by the end of 2001 as a result of the successful drilling program and installation of the processing plant.

PERMIAN and EAST TEXAS BASINS

In 2001, the Company drilled or participated in 32 wells in Texas, realizing a 75% success rate, and two wells were drilling at year-end. The Permian and East Texas basins represent 13% and 17% of Tom Brown's total reserves and production, respectively. The Company's activities in Texas are heavily weighted towards exploration opportunities. Two of the Company's more significant exploration plays in Texas are the horizontal Devonian/Montoya in the Permian Basin and the horizontal James Lime in the East Texas Basin.

PARADOX BASIN

	2001	2000	1999
PRODUCTION [Mmcfepd]	39.7	34.3	16.5
TOTAL GROSS ACREAGE [in thousands]	345	236	219
TOTAL NET ACREAGE [in thousands]	322	221	203
E&P CAPITAL SPENDING [$s in MM]	$20.9	$11.5	$1.3
LEASE OPERATING EXPENSE [per Mcfe]	$0.64	$0.68	$0.73

Tom Brown grew production in Andy's Mesa field

In the Permian Basin, the Company in mid-2001 completed drilling the G. Lyda #1, a horizontal Montoya well, at its Deep Valley prospect area, which tested non-commercial in the Montoya formation. Tom Brown is continuing to explore the Deep Valley Prospect and in early 2002 commenced operations to re-enter an existing well and to drill a horizontal test of the Devonian formation (which is stratigraphically above the Montoya formation). In addition, the Company, as operator, along with its partners completed shooting a 240 square mile 3-D seismic survey in 2001 and have recently begun interpretation. During 2001, the Company drilled seven wells in the horizontal James Lime play in east Texas. Five of the seven wells have been completed and connected to a sales line at an average initial gross production rate of 2.6 Mmcfpd, one well is waiting on a sales line and one well was temporarily abandoned. This large regional play is in its early stages of development and Tom Brown is working to determine its potential based upon the initial production rates and variable decline rates of the wells drilled to date. The Company continues to evaluate other technology, including fracture stimulation of the wells and the drilling of multiple horizontal laterals, to enhance the economics of the play. Tom Brown has over 80,000 net acres in this trend and has commenced shooting 172 square miles of 3-D seismic in two prospect areas to help evaluate the James Lime and additional productive formations in the area.

PERMIAN/EAST TEXAS

	2001	2000	1999
PRODUCTION [Mmcfepd]	35.8	34.4	34.4
TOTAL GROSS ACREAGE [in thousands]	278	234	163
TOTAL NET ACREAGE [in thousands]	166	113	71
E&P CAPITAL SPENDING [$s in MM]	$58.0	$22.5	$4.0
LEASE OPERATING EXPENSE [per Mcfe]	$0.35	$0.32	$0.29

from 1.5 Mmcfpd in 2000 to 19.5 Mmcfpd in 2001.

CANADA

Tom Brown completed the \$95 million acquisition of Stellarton Energy in January of 2001. Canada represents 11% of Tom Brown's total year-end reserves and 2001 production.

Tom Brown, in 2001, drilled 35 wells in Canada, realizing a 65% success rate. The majority of the activity was focused in the Carrot Creek/Edson and Davey Lake areas, where 21 and three wells were drilled, respectively. During this transition year, the primary focus was on establishing a strong management team in Canada and selectively upgrading certain technical and operating staff positions. Additionally, the Company expanded its plant processing capabilities in Carrot Creek and established new opportunities through the acquisition of additional land and seismic on internally-generated prospects.

2002 EXPLORATION AND DEVELOPMENT

The initial exploration and development capital expenditures budget has been set in the range of \$115 - \$125 million. Tom Brown remains committed to an active exploration program in 2002. Approximately 25% of the budget is being allocated to exploration activities, with plans to drill several wildcats in most of our core basins, testing various basin centered, coal bed methane and conventional play types.

PRINCIPAL OFFICERS

James D. Lightner
President and Chief Executive Officer
Age: 49
Employed with the Company Since: 1999

Daniel G. Blanchard
Executive Vice President, Chief Financial Officer and Treasurer
Age: 41
Employed with the Company Since: 1999

Bruce R. DeBoer
Vice President, General Counsel and Secretary
Age: 49
Employed with the Company Since: 1997

Doug R. Harris
Vice President - Operations
Age: 47
Employed with the Company Since: 2001

Thomas W. Dyk
Executive Vice President and Chief Operating Officer
Age: 48
Employed with the Company Since: 1998

Peter R. Scherer
Executive Vice President and General Manager of the Southern Region
Age: 45
Employed with the Company Since: 1982

Rodney G. Mellott
Vice President - Land and Business Development
Age: 44
Employed with the Company Since: 1999

DIRECTORS

James B. Wallace
Chairman of the Board of Directors, Partner in Brownlie, Wallace, Armstrong, and Bander Exploration

James D. Lightner
President and Chief Executive Officer of Tom Brown, Inc.

Thomas C. Brown
Chairman and Chief Executive Officer of TMBR/Sharp Drilling Co., Inc.

Henry Groppe
Partner in Groppe, Long & Littell

Robert H. Whilden
Senior Vice President, General Counsel and Secretary of BMC Software, Inc.

David M. Carmichael
Private Investor

Kenneth B. Butler
Vice President of Unocal Gulf Region U.S.A. Business Unit of Union Oil Company of California

Edward W. LeBaron, Jr.
Partner in LeBaron Ranches L.P.

Wayne W. Murdy
Director, Chairman and Chief Executive Officer of Newmont Mining Corporation

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [FEE REQUIRED]

For the Fiscal Year Ended December 31, 2001

or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]

For the Transition Period from to

Commission File Number 0-3880

Tom Brown, Inc.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	95-1949781 (I.R.S. Employer Identification No.)
555 Seventeenth Street Suite 1850 Denver, Colorado (Address of principal executive offices)	80202 (Zip Code)

303-260-5000
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act: None

Securities Registered Pursuant to Section 12(g) of the Act:
Common Stock, $.10 par Value
Convertible Preferred Stock, $.10 par Value
(Title of Class)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. Yes ☐ No ☐

The aggregate market value of the Registrant's Common Stock held by non-affiliates (based upon the last sale price of $27.23 per share as quoted on the NASDAQ National Market System) on March 11, 2002 was approximately $1,066,275,700.

As of March 11, 2002, there were 39,158,124 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2001 Annual Meeting of Stockholders to be held on May 9, 2002 are incorporated by reference into Part III.

TOM BROWN, INC.

FORM 10-K

CONTENTS

PART I

ITEM 1. *Business*

General

Tom Brown, Inc. (the "Company") was organized in 1955 as a privately-owned drilling company known as Scarber-Brown Drilling Company and in 1959 as Tom Brown Drilling Company, Inc. In 1968, the Company merged into Gold Metals Consolidated Mining Company, a publicly-traded Nevada corporation. The name of the Company after the merger was changed to Tom Brown Drilling Company, Inc. and to Tom Brown, Inc. in 1971. In February 1987, the Company changed its state of incorporation from Nevada to Delaware. In 1999, the Company relocated its headquarters and executive offices to 555 Seventeenth Street, Suite 1850, Denver, Colorado 80202 and its telephone number at that address is (303) 260-5000. Unless the context otherwise requires, all references to the "Company" include Tom Brown, Inc. and its subsidiaries.

The Company is engaged primarily in the exploration for, and the acquisition, development, production, marketing, and sale of, natural gas, natural gas liquids and crude oil in North America. The Company's activities are conducted principally in the Wind River and Green River Basins of Wyoming, the Piceance Basin of Colorado, the Paradox Basin of Utah and Colorado, the Val Verde Basin of west Texas, the Permian Basin of west Texas and southeastern New Mexico, the East Texas Basin and the Western Alberta area of Canada. The Company also, to a lesser extent, conducts exploration and development activities in other areas of the continental United States and Canada.

In December 2000, the Company initiated a cash tender for all the outstanding stock of Stellarton Energy Corporation ("Stellarton"). This transaction was completed on January 12, 2001.

The Company's industry segments are (i) the exploration for, and the acquisition, development and production of, natural gas, natural gas liquids and crude oil, (ii) the marketing, gathering, processing and sale of natural gas and (iii) the drilling of gas and oil wells.

Except for its gas and oil leases with governmental entities and other third parties who enter into gas and oil leases or assignments with the Company in the regular course of its business and options to purchase gas and oil leases with the Eastern Shoshone and Northern Arapaho Tribes, the Company has no material patents, licenses, franchises or concessions which it considers significant to its gas and oil operations.

The nature of the Company's business is such that it does not maintain or require a substantial amount of products, customer orders or inventory. The Company's gas and oil operations are not subject to renegotiations of profits or termination of contracts at the election of the federal government.

The Company has not been a party to any bankruptcy, receivership, reorganization or similar proceeding, except in connection with its participation as a joint proponent of a plan of reorganization for Presidio Oil Company in 1996.

Business Strategy

The Company's business strategy is to increase shareholder value through the discovery, acquisition and development of long-lived gas and oil reserves in areas where the Company has industry knowledge and operations expertise. The Company's principal investments have been in natural gas prone basins, which the Company believes will continue to provide the opportunity to accumulate significant long-lived gas and oil reserves at attractive prices. The expansion into Canada in 2001 was an extension of this fundamental strategy.

The Company's year-end domestic acreage position was approximately 3,023,000 gross (1,929,000 net) acres (including options) located primarily in the Wind River and Green River Basins of Wyoming, the Piceance Basin of Colorado, the Paradox Basin of Colorado and Utah, and the Permian, Val Verde and East Texas Basins of Texas where the Company can utilize its geological and technical expertise and its control of operations for the further development and expansion of these areas. Approximately 90% of the net acreage is undeveloped.

The Company's year-end Canadian acreage position located in Western Alberta was approximately 519,000 gross (351,000 net) acres. Approximately 60% of the net acreage is undeveloped.

Additionally, by staying focused in its core basins, the Company continues to develop more effective drilling and completion techniques which can improve overall economic efficiency.

The Company increased its reserves in 2001 over 2000 by 21% due primarily to continued drilling success in its core areas and the acquisition of reserves primarily associated with the Canadian Stellarton transaction. Year-end proved reserves were 732 billion cubic feet equivalent ("Bcfe"), compared to year-end 2000 reserves of 603 Bcfe. At December 31, 2001, the Canadian reserve base (as adjusted for negative price revisions, extensions and discoveries and performance adjustments subsequent to the January 2001 acquisition date) was 77 Bcfe. Since December 31, 1995, the Company has increased proved reserves at a compounded annual growth rate of 25%, or from 188 Bcfe to 732 Bcfe.

Reserve replacement for 2001 was 294% from all sources and 191% from extensions, discoveries and revisions only. Finding cost was $1.52 per Mcfe for the year from all sources and a 3-year average finding cost of $1.09 per Mcfe. The Company's reserve to production ratio was 9.6 years at year-end 2001 compared to 9.7 years at year-end 2000. In addition to increasing reserves, the Company also increased its production 23% from 62.3 Bcfe in 2000 to 76.4 Bcfe in 2001.

The Company markets a portion of its operated gas production and third party gas in the Rocky Mountains through Retex, Inc. ("Retex"), the Company's wholly-owned marketing subsidiary.

The Company also conducts gas gathering and processing activities in the Rocky Mountain area. Initially, these functions were conducted through Wildhorse Energy partners, LLC ("Wildhorse") which was owned 55% by Kinder Morgan, Inc. ("KM") and 45% by the Company. In November 2000, these gathering and processing assets were distributed to the Company in anticipation of the dissolution of Wildhorse. KM received the storage facility and a cash payment. TBI Field Services, Inc. ("TBIFS") was formed as a wholly-owned subsidiary of Tom Brown, Inc. to administer these gathering and processing assets. In 2001, TBIFS selectively sold many of the gathering and processing facilities received in the Wildhorse asset distribution, retaining only those gathering systems considered integral to the Company's gas and oil reserve base. The Company also directly owns and operates several gas processing facilities adjacent to its areas of operations.

The Company plans to continue to selectively pursue acquisitions of gas and oil properties in its core areas of activity and, in connection therewith, the Company from time to time will be involved in evaluations of, or discussions with, potential acquisition candidates. The consideration for any such acquisition might involve the payment of cash and/or the issuance of equity or debt securities.

Notwithstanding the Company's historical ability to implement the above strategy, there can be no assurance that the Company will be able to successfully implement its strategy in the future.

Areas of Activity

The following discussion focuses on areas the Company considers to be its core areas of operations and those that offer the Company the greatest opportunities for further exploration and development activities.

Wind River, Green River, Paradox, and Piceance Basins

The Wind River and Green River Basins of Wyoming, the Piceance Basin of Colorado, and the Paradox Basin of Colorado and Utah account for a major portion of the Company's current and anticipated domestic exploration and development activities with approximately 75% of the Company's proved reserves at December 31, 2001. The Company owns interests in 1,329 producing wells in these basins that averaged net daily production of 137.9 Mmcfe for 2001. The Company has approximately 1,685,000 gross (1,282,000 net) developed and undeveloped acres in these basins, including option acreage of approximately 437,000 gross undeveloped (315,000 net) acres in the Wind River Basin.

Although the Wind River Basin experienced limited natural gas transportation capacity in the past, pipeline expansions and conversions have worked to correct this capacity constraint. Recognizing these restrictions, various pipelines have constructed lines into this area which have added capacity to move additional gas volumes.

Permian and Val Verde Basins

The Permian and Val Verde Basins accounted for approximately 8% of the Company's proved reserves at December 31, 2001. The Company's share of production from these basins averaged 36 Mmcfepd of natural gas for 2001. The Company holds between 30% to 50% working interests in approximately 33,000 gross (16,000 net) acres and 90 producing wells in the Val Verde Basin. The Permian Basin contains significant oil reserves for the Company, located primarily in the Spraberry Field. The Company owns interests in 288 wells and has approximately 155,000 gross (83,000 net) developed and undeveloped acres in this basin.

In the Permian Basin, the Company drilled a horizontal Montoya well in 2001, at its Deep Valley prospect area, which tested non-commercial in the Montoya formation but is still being evaluated in the Devonian formation. The Company is continuing to explore at its Deep Valley prospect and plans to re-enter an existing well and to drill a horizontal test of the Devonian formation, which is stratigraphically above the Montoya formation in the first quarter of 2002. In addition, the Company, as operator, along with its partners completed shooting a 240 square mile 3-D seismic survey in 2001 and began interpretation in early 2002.

East Texas Basin

Together with Marathon Oil Corporation, the Company participates in a continuing developmental drilling program in the Mimms Creek Field in Freestone County, Texas. During 2001, eight wells were drilled under this program, with the Company owning working interests ranging from 28% to 62.5%. The Company has acquired approximately 80,000 net acres in the James Lime (horizontal) Trend of the East Texas Basin, and in 2001, drilled seven wells in this play. Five of the seven wells have been completed and connected to a sales line, one well is waiting on a sales line and one well was temporarily abandoned. This large regional play is in its early stages of development and the Company is working to determine its potential based upon the initial production rates and variable decline rates of the wells drilled to date.

Canada

The Western Canada Sedimentary Basin accounted for approximately 11% of the Company's proved reserves at December 31, 2001. The Company's share of production from this basin averaged 23 Mmcfepd of natural gas for 2001. The Company owns interests in 241 wells and has approximately 519,000 gross (351,000 net) developed and undeveloped acres in this area.

Business Developments

Current Developments in the Gas and Oil Business

Acquisition of Stellarton Energy Corporation

Effective January 16, 2001, the Company completed the purchase of 100% of Stellarton Energy Corporation ("Stellarton"), in a transaction valued at $95 million, which was funded through a five-year Canadian term loan. Stellarton's assets are located in Western Alberta, Canada with estimated total net proved reserves (after royalty) of 58.8 billion cubic feet (Bcf) of gas and 2.82 million barrels of oil and natural gas liquids for total equivalent proved reserves of 75.5 Bcfe, as of the date of the acquisition.

Acquisition of Rocky Mountain Assets

In June 2000, the Company purchased an additional working interest in the Company operated Pavillion Field in the Wind River Basin in Wyoming. The acquired interests included an estimated 24 Bcfe of proved reserves purchased for total consideration of $15.2 million net of normal closing adjustments.

In September 1999, the Company purchased certain Rocky Mountain assets from an undisclosed seller for approximately $7.7 million in cash. Included in the acquisition was approximately 9.7 Bcfe of proved reserves and 34,000 net acres in the Greater Green River Basin of Wyoming.

Acquisition of the Assets of Unocal Corporation

In July 1999, the Company completed an acquisition of substantially all of the Rocky Mountain oil and gas assets of Unocal Corporation ("Unocal") for 5.8 million shares of common stock and $5 million in cash for a total purchase price of $68.5 million ($60.9 million after deducting normal purchase price adjustments).

The Unocal oil and gas assets are primarily located in the Paradox Basin of southwestern Colorado and southeastern Utah. These assets and properties complimented the Company's undeveloped average position in the Paradox Basin.

Included in the acquisition was the Lisbon Plant, a modern sophisticated cyrogenic (60 million cubic feet per day inlet capacity) natural gas processing plant that extracts natural gas liquids and merchantable helium; and separates carbon dioxide, hydrogen sulfide and nitrogen from the raw gas stream. The net proved reserves of these Unocal properties were estimated to be 93.2 billion cubic feet equivalent of gas as of the closing date of July 1, 1999. Approximately 65,000 net undeveloped acres were also acquired.

Current Developments in the Marketing, Gathering and Processing Business

In September 1999, KM became the operator of, and 55% partner in, Wildhorse as a result of a merger with KN Energy, Inc. ("KNE"). Wildhorse was formed in connection with the Company's 1996 acquisition of KN Production Company, the wholly-owned oil and gas production subsidiary of KNE. Wildhorse was created to provide services related to natural gas, natural gas liquids and other natural gas products, including gathering, processing and storage services and field services. The Company owned 45% of Wildhorse since its inception. Effective September 1, 1999, Wildhorse assigned 100% of its marketing operations to Retex, the Company's wholly-owned marketing subsidiary. Additionally, firm transportation contracts were assigned 55% to KM and 45% remained in Retex. In November 2000, the Wildhorse gathering and processing assets were distributed to the Company in anticipation of the dissolution of Wildhorse. KM received the Wildhorse storage facility and a cash payment. "TBIFS" was formed as a wholly-owned subsidiary of Tom Brown, Inc. to administer the gathering and processing assets received in this distribution.

In 2001, TBIFS selectively sold many of the gathering and processing facilities received in the Wildhorse asset distribution. The principal asset retained in this process was the Wind River gathering system in one of the Company's core areas.

Current Developments in the Drilling Business

Acquisition of Assets of W. E. Sauer Companies, LLC

On January 7, 1998, the Company completed the acquisition of all of the drilling assets of W. E. Sauer Companies L.L.C. of Casper, Wyoming for approximately $8.1 million. The Company operates the assets in its subsidiary, Sauer Drilling Company ("Sauer"), and will continue to serve the drilling needs of operators in the central Rocky Mountain region in addition to drilling for the Company. The assets included five drilling rigs, tubular goods, a yard and related assets. Subsequent to the acquisition, Sauer has acquired three additional drilling rigs for approximately $4 million in total.

Markets

The Company's gas production has historically been sold under month-to-month contracts with marketing companies. During 2001, there was a significant amount of volatility in the prices received for natural gas. Monthly closing gas prices as measured on the New York Mercantile Exchange ("NYMEX") varied from a high of $9.98 per million British thermal unit ("Mmbtu") for January 2001 to a low of $1.83 per Mmbtu for October 2001. The Company produced approximately 59% of its gas production for 2001 from the Rocky Mountain area where the price of gas varied as compared to NYMEX prices from $1.43 per Mmbtu below NYMEX prices in July 2001 to $.02 above NYMEX prices in February 2001. Production from the Company's new Canadian production base has also been subject to price volatility. In 2001, gas production from the Canadian fields was subject to gas pricing that ranged from $1.10 (USD) per Mmbtu above the February 2001 NYMEX price to a price that was $.98 (USD) per Mmbtu below the October 2001 NYMEX price.

The Company markets most of its oil production with independent third-party resellers and refiners at market ("posted") prices. These posted prices generally reflect the prices determined by the trading of West Texas Intermediate ("WTI") oil futures contracts on the NYMEX, with adjustments due to basis differential and for the quality of oil produced.

NYMEX prices for both gas and oil are influenced by weather, seasonal demand, levels of storage, production levels and a variety of political and economic factors over which the Company has no control.

Production Volumes, Unit Prices and Costs

The following table sets forth certain information regarding the Company's volumes of production sold and average prices received associated with its production and sales of natural gas, natural gas liquids and crude oil for each of the years ended December 31, 2001, 2000 and 1999.

	Years Ended December 31,		
United States	2001	2000	1999
Production Volumes:			
Natural Gas (MMcf)	57,163	51,199	40,514
Crude Oil (Mbbls)	723	773	909
Natural Gas Liquids (Mbbls)	1,074	1,074	535
Net Average Daily Production Volumes:			
Natural Gas (Mcf)	156,611	139,888	110,997
Crude Oil (Bbls)	1,979	2,113	2,491
Natural Gas Liquids (Mbbls)	2,943	2,934	1,467
Average Sales Prices:			
Natural Gas (per Mcf) (1)	$ 3.73	$ 3.46	$ 2.04
Crude Oil (per Bbl)	$ 22.64	$ 28.05	$ 16.98
Natural Gas Liquids (per Bbl)	$ 13.25	$ 16.77	$ 12.16
Average Production Cost (per Mcfe) (2)	$ .70	$ .76	$ .58

(1) Includes the effects of hedging.

(2) Includes production costs and taxes on production. (Mcfe means one thousand cubic feet of natural gas equivalent, calculated on the basis of six barrels of oil and natural gas liquids to one Mcf of gas.)

Canada	Year Ended December 31, 2001
Production Volumes:	
Natural Gas (MMcf)	6,661
Crude Oil (Mbbls)	158
Natural Gas Liquids (Mbbls)	143
Net Average Daily Production Volumes:	
Natural Gas (Mcf)	18,247
Crude Oil (Bbls)	432
Natural Gas Liquids (Mbbls)	392
Average Sales Prices:	
Natural Gas (per Mcf)	$ 3.49
Crude Oil (per Bbl)	$ 25.11
Natural Gas Liquids (per Bbl)	$ 20.23
Average Production Cost (per Mcfe)	$ .62

Competition

The Company encounters strong competition from major oil companies and independent operators in acquiring properties and leases for the exploration for, and the development and production of, natural gas and crude oil. Competition is particularly intense with respect to the acquisition of desirable undeveloped gas and oil leases. The principal competitive factors in the acquisition of undeveloped gas and oil leases include the availability and quality of staff and data necessary to identify, investigate and purchase such leases, and the financial resources necessary to acquire and develop such leases. Many of the Company's competitors have financial resources, staffs and facilities substantially greater than those of the Company. In addition, the producing, processing and marketing of natural gas and crude oil is affected by a number of factors which are beyond the control of the Company, the effect of which cannot be accurately predicted.

The principal raw materials and resources necessary for the exploration and development of natural gas and crude oil are leasehold prospects under which gas and oil reserves may be discovered, drilling rigs and related equipment to drill for and produce such reserves and knowledgeable personnel to conduct all phases of gas and oil operations. The Company must compete for such raw materials and resources with both major oil companies and independent operators.

Retex encounters competition from other natural gas transportation and marketing entities in the marketing of gas. Such competition may materially affect the volumes and margins that Retex may derive.

Executive Officers of the Company

On January 19, 2001, Donald L. Evans, the Company's Chairman of the Board and Chief Executive Officer resigned to accept an appointment as the Secretary of the U.S. Department of Commerce. The Company's Board of Directors elected James B. Wallace as the new Chairman of the Board and James D. Lightner to the additional position of Chief Executive Officer.

The executive officers of the Company on March 13, 2002 were as follows:

Name	Age	Position with Company	Since
James B. Wallace	72	Chairman of the Board	2001
James D. Lightner	49	President, Chief Executive Officer and Director	1999
Thomas W. Dyk	48	Executive Vice President and Chief Operating Officer	1998
Peter R. Scherer	45	Executive Vice President	1982
Daniel G. Blanchard	41	Executive Vice President, Chief Financial Officer and Treasurer	1999
Rodney G. Mellott	44	Vice President — Land and Business Development	1999
Bruce R. DeBoer	49	Vice President, General Counsel and Secretary	1997
Doug R. Harris	47	Vice President — Operations	2001

Each executive officer is elected annually by the Company's Board of Directors to serve at the Board's discretion.

Employees

At December 31, 2001, the Company had 546 employees of which 211 were employed by Sauer. None of the Company's employees are represented by labor unions or covered by any collective bargaining agreement. The Company considers its relations with its employees to be satisfactory.

Regulation — United States

Regulation of Gas and Oil Production

Gas and oil operations are subject to various types of regulation by state and federal agencies. Legislation affecting the gas and oil industry is under constant review for amendment or expansion. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the gas and oil industry and its individual members, some of which carry substantial penalties for failure to comply. The regulatory burden on the gas and oil industry increases the Company's cost of doing business and, consequently, affects its profitability.

States in which the Company conducts its gas and oil activities regulate the production and sale of natural gas and crude oil, including requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of gas and oil resources. In addition, most states regulate the rate of production and may establish maximum daily production allowables for wells on a market demand or conservation basis.

Gas Price Controls

Prior to January 1993, certain natural gas sold by the Company was subject to regulation by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 ("NGPA"). The NGPA prescribed maximum lawful prices for natural gas sales effective December 1, 1978. Effective January 1, 1993, natural gas prices were completely deregulated and sales of the Company's natural gas are now made at market prices. The majority of the Company's gas sales contracts either contain decontrolled price provisions or already provide for market prices.

Oil Price Controls

Sales of crude oil, condensate and gas liquids by the Company are not regulated and are made at market prices.

Environmental Regulation

The Company's activities are subject to federal and state laws and regulations governing environmental quality and pollution control. The existence of such regulations has a material effect on the Company's operations but the cost of such compliance has not been material to date. However, the Company believes that the gas and oil industry may experience increasing liabilities and risks under the Comprehensive Environmental Response, Compensation and Liability Act, as well as other federal, state and local environmental laws, as a result of increased enforcement of environmental laws by various regulatory agencies. As an "owner" or "operator" of property where hazardous materials may exist or be present, the Company, like all others in the petroleum industry, could be liable for fines and/or "clean-up" costs, regardless of whether the Company was responsible for the release of any hazardous substances.

Rocno Corporation ("Rocno"), a wholly-owned subsidiary of the Company, is a party to a trust agreement in connection with the environmental clean-up plan for the Sheridan Superfund Site in Waller County, Texas. See Item 3, Legal Proceedings.

Indian Lands

The Company's Muddy Ridge and Pavillion Fields are located on the Wind River Indian Reservation. The Eastern Shoshone and Northern Arapaho Tribes regulate certain aspects of the production and sale of natural gas and crude oil, and the drilling of wells and levy taxes on the production of hydrocarbons. The Bureau of Indian Affairs and the Minerals Management Service of the United States Department of the Interior perform certain regulatory functions relating to operation of Indian gas and oil leases. The Company owns interests in three leases in the Pavillion Field which were issued pursuant to the provisions of the Act of August 21, 1916, for initial terms of 20 years each, with a preferential right by the lessee to renew the leases for subsequent ten-year terms. The leases were renewed for an additional ten-year term in 1992, effective as of June 23, 1993. These leases have been amended to provide for incremental extensions of this lease term of up to an additional twelve years by drilling and completing additional wells on each lease prior to June 2003. In December of 2000 the Company added to its Tribal base inventory around the Pavillion Field by signing ten additional ten-year leases covering nearly 25,800 net acres. The Company is currently awaiting final approval of the leases by the Bureau of Indian Affairs.

Regulation — Canada

Regulation of Gas and Oil Production and Price Controls

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect our operations in a manner materially different than they would affect other oil and gas companies of similar size.

In Canada, oil and gas exports are subject to regulation by the National Energy Board (NEB), an independent federal regulatory agency. The Company does not, at present, export oil or gas under the terms of these regulations, but may be affected if regulations imposed by the NEB act to restrict the sales of gas and oil by other companies. Exports are also subject to the North American Free Trade Agreement (NAFTA) which became effective on January 1, 1994. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the United States or Mexico will be allowed provided that any export restrictions do not: (i) reduce the proportion of energy resource exported relative to domestic use (based upon the proportion prevailing in the most recent 36-month period), (ii) impose an export price higher than the domestic price, and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements. NAFTA contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

The provincial government of Alberta also regulates the volume of natural gas which may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime on Crown lands is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time the governments of Canada and Alberta have established incentive programs which have included royalty rate deductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects. At present, few of these programs are currently in effect.

In Alberta, certain producers of oil or natural gas are currently entitled to a credit against the royalties to the Crown by virtue of the ARTC (Alberta royalty tax credit) program. The credit is determined by applying a specified rate to a maximum of $2 million CDN of Alberta Crown royalties payable for each producer or associated group of producers. The specified rate is a function of the Royalty Tax Credit reference price (RTCRP) which is set quarterly by the Alberta Department of Energy and ranges from 25% to 75%, depending on oil and gas par prices for the previous calendar quarter. The provincial government of Alberta has proposed changes to the ARTC program which have not been finalized.

Environmental Regulation

In Canada, the oil and natural gas industry is currently subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities.

In Alberta, environmental compliance has been governed by the Alberta Environmental Protection and Enhancement Act ("AEPEA") since September 1, 1993. In addition, AEPEA also imposes certain environmental responsibilities on oil and natural gas operators in Alberta and in certain instances also imposes penalties for violations.

ITEM 2. *Properties*

Gas and Oil Properties

The principal properties of the Company consist of developed and undeveloped gas and oil leases. Generally, the terms of developed gas and oil leaseholds are continuing and such leases remain in force by virtue of, and so long as, production from lands under lease is maintained. Undeveloped gas and oil leaseholds are generally for a primary term, such as five or ten years, subject to maintenance with the payment of specified minimum delay rentals or extension by production. The Company also has options to lease undeveloped gas and oil leaseholds on Eastern Shoshone and Northern Arapaho Tribal lands. The oil and gas leases must be renewed after twenty years and the Company has a preferential right to negotiate with the Tribes for such renewal.

Title to Properties

As is customary in the gas and oil industry, the Company makes only a cursory review of title to undeveloped gas and oil leases at the time they are acquired by the Company. However, before drilling commences, the Company causes a thorough title search to be conducted, and any material defects in title are remedied prior to the time actual drilling of a well on the lease begins. The Company believes that it has good title to its gas and oil properties, some of which are subject to immaterial encumbrances, easements and restrictions. The gas and oil properties owned by the Company are also typically subject to royalty and other similar non-cost bearing interests customary in the industry. The Company does not believe that any of these encumbrances or burdens materially affects the Company's ownership or use of its properties.

Acreage

The following table sets forth the gross and net acres of developed and undeveloped gas and oil leases held by the Company at December 31, 2001. Excluded from the table are approximately 437,000 gross (315,000 net) acres in Wyoming under gas and oil option agreements acquired from certain Indian tribes.

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Colorado	101,600	82,319	604,683	481,267
Louisiana	10,045	3,892	6,152	1,649
Michigan	—	—	303	121
Montana	4,678	718	158,307	26,443
Nebraska	—	—	31,455	30,861
New Mexico	15,417	3,952	2,440	2,096
North Dakota	3,720	105	5,880	112
Texas	107,167	37,906	315,675	197,148
Utah	6,799	5,521	101,589	94,912
West Virginia	3,852	1,240	153,206	76,920
Wyoming	138,234	63,513	815,165	503,577
Canada	258,200	139,100	260,500	211,800
Other	—	—	10	2
Total	649,712	338,266	2,455,365	1,626,908

"Gross" acres refer to the number of acres in which the Company owns a working interest. "Net" acres refer to the sum of the fractional working interests owned by the Company in gross acres.

Gas and Oil Reserves

Estimates of the Company's gas and oil reserves at December 31, 2001 and 2000, including future net revenues and the present value of future net cash flows, were prepared by the Company's petroleum engineering staff and audited by Ryder Scott (independent petroleum consultants). The reserve estimates were prepared by Ryder Scott at December 31, 1999. Guidelines established by the Securities and Exchange Commission (the "SEC") were utilized to prepare these reserve estimates. Estimates of gas and oil reserves and their estimated values require numerous engineering assumptions as to the productive capacity and production rates of existing geological formations and require the use of certain SEC guidelines as to assumptions regarding costs to be incurred in developing and producing reserves and prices to be realized from the sale of future production.

Accordingly, estimates of reserves and their value are inherently imprecise and are subject to constant revision and change and should not be construed as representing the actual quantities of future production or cash flows to be realized from the Company's gas and oil properties or the fair market value of such properties.

Certain additional unaudited information regarding the Company's reserves, including the present value of future net cash flows, is set forth in Note 15 of the Notes to Consolidated Financial Statements included herein.

The Company has no gas and oil reserves or production subject to long-term supply or similar agreements with foreign governments or authorities.

Estimates of the Company's total proved gas and oil reserves have not been filed with or included in reports to any federal authority or agency other than the SEC.

Productive Wells

The following table sets forth the gross and net productive gas and oil wells in which the Company owned an interest at December 31, 2001.

	Productive Wells			
	Gross		Net	
	Gas	Oil	Gas	Oil
Colorado	695	4	342.99	3.13
Louisiana	38	30	10.23	8.67
New Mexico	26	26	5.91	6.04
Utah	13	19	12.23	18.91
Texas	164	278	67.34	95.79
West Virginia	131	—	32.95	—
Wyoming	731	267	292.44	46.67
Canada	151	90	74.00	24.40
Other	21	6	1.47	.80
Total	1,970	720	839.56	204.41

A "gross" well is a well in which the Company owns a working interest. "Net" wells refer to the sum of the fractional working interests owned by the Company in gross wells.

Gas and Oil Drilling Activity

The following table sets forth the Company's gross and net interests in exploratory and development wells drilled during the periods indicated. The relative net percentage of the wells drilled by type and category is also disclosed.

	United States			Canada			United States					
	Years Ended December 31,											
	2001			2001			2000			1999		
Type of Well	Gross	Net	Net%	Gross	Net	Net%	Gross	Net	Net%	Gross	Net	Net%
Exploratory												
Gas	7	6.6	49	—	—	—	—	—	—	2	.8	20
Oil	—	—	—	—	—	—	—	—	—	—	—	—
Dry	12	6.7	51	4	3.6	100	3	2.3	100	4	3.2	80
	19	13.3	100	4	3.6	100	3	2.3	100	6	4.0	100
Development												
Gas	139	98.1	97	22	16.0	71	63	33.7	93	37	16.3	99
Oil	—	—	—	1	.5	2	1	.2	1	1	0.2	1
Dry	7	3.3	3	8	6.1	27	4	2.3	6	—	—	—
	146	101.4	100	31	22.6	100	68	36.2	100	38	16.5	100
Total	165	114.7		35	26.1		71	38.5		44	20.5	

At December 31, 2001, 14 gross (10 net) development wells and 2 gross (.9 net) exploration wells were in various stages of drilling and completion in Texas, Colorado, and Wyoming, while 4 gross (2.6 net) development wells were in various stages of drilling and completion in Canada.

Other Properties

The Company leases its corporate office facilities in Denver, Colorado. The lease covers approximately 56,500 square feet and expires January 31, 2004. Of this amount, the Company subleases 7,246 square feet under an agreement that expires January 31, 2004.

The Company leases office facilities in Midland, Texas. The lease covers approximately 33,150 square feet for a term of five years and expires December 31, 2003.

The Company also leases office facilities in Calgary, Alberta. The lease covers approximately 14,600 square feet for a term of five years and expires August 31, 2004.

The Company owns a 3,200 square foot building located on a 2.94 acre tract in Midland, Texas. The facility is used primarily for storage of pipe and oilfield equipment.

ITEM 3. *Legal Proceedings*

The Company is a defendant in several routine legal proceedings incidental to its business, which the Company believes will not have a significant effect on its consolidated financial position, results of operations or cash flows.

In addition to routine legal proceedings incidental to the Company's business, Rocno was a defendant in a complaint filed by the United States of America which, among other things, alleged that Rocno and approximately 117 other companies arranged for the disposal of "hazardous materials" (within the meaning of the Comprehensive Environmental Response, Compensation and Liability Act) in Waller County, Texas (the "Sheridan Superfund Site"). Effective August 31, 1989, Rocno and thirty-six other defendants executed the Sheridan Site Trust Agreement (the "Trust") for the purpose of creating a trust to perform agreed upon remedial action at the Sheridan Superfund Site. In connection with the establishment of the Trust, the parties to the Trust have agreed to the terms of a Consent Decree entered December 3, 1991 in the United States District Court, Southern District of Texas, Houston Division, Civil Action No. H-91-3529, pursuant to which the defendants joining the Consent Decree will carry out the clean-up plan prescribed by the Consent Decree. The estimate of the total clean-up cost is approximately $30 million. Under terms of the Trust, each party is allocated a percentage of costs necessary to fund the Trust for clean-up costs. Rocno's proportionate share of the estimated clean-up costs is 0.33% or $99,000, of which $16,000 has been paid, and the remainder was accrued in the Company's consolidated financial statements. If the clean-up costs exceed the projected amount, Rocno will be required to pay its pro rata share of the excess clean-up costs.

ITEM 4. *Submission of Matters to a Vote of Security Holders*

No matters were submitted to a vote of the Company's stockholders in the fourth quarter of the year ended December 31, 2001.

PART II

ITEM 5. *Market for Registrant's Common Equity and Related Stockholder Matters*

The Company's Common Stock is traded in the over-the-counter market and appears on the NASDAQ National Market System under the symbol "TMBR". The following table sets forth the range of high and low closing quotations for each quarterly period during the past two fiscal years as reported by NASDAQ National Market System. The quotations are inter-dealer prices without retail mark-ups, mark-downs or commissions and may not represent actual transactions.

Quarter Ended	Closing Sale Price	
	High	Low
March 31, 2000	18.38	12.00
June 30, 2000	23.06	17.75
September 30, 2000	24.50	17.00
December 31, 2000	36.00	20.44
March 31, 2001	35.25	29.56
June 30, 2001	32.99	23.34
September 30, 2001	27.45	20.16
December 31, 2001	27.46	20.20

On March 11, 2002 the last sale price of the Company's Common Stock, as reported by the NASDAQ National Market System, was $27.23 per share.

The transfer agent for the Company's Common Stock is EquiServe Trust Company, N.A., Canton, Massachusetts.

On December 31, 2001, the outstanding shares of the Company's Common Stock (39,127,649 shares) were held by approximately 1,843 holders of record.

The Company has never declared or paid any cash dividends to the holders of Common Stock and has no present intention to pay cash dividends to the holders of Common Stock in the future. Under the terms of the Company's Credit Agreement, the Company is prohibited from paying cash dividends to the holders of Common Stock without the written consent of the bank lenders.

In January 1996, in connection with the acquisition of KN Production Company, ("KNPC") the Company issued 1,000,000 shares of its $1.75 Convertible Preferred Stock, Series A (the "Preferred Stock") to the seller. The Preferred Stock was exchangeable, in whole or in part, at the option of the Company on any dividend payment date at any time on or after March 15, 1999, and prior to March 15, 2001, for shares of Common Stock at the exchange rate of 1.666 shares of Common Stock for each share of Preferred Stock; provided that (i) on or prior to the date of exchange, the Company shall have declared and paid or set apart for payment to the holders of Preferred Stock all accumulated and unpaid dividends to the date of exchange, and (ii) the current market price of the Common Stock is above $18.375 (the "Threshold Price"). On June 15, 2000, the Company elected to exchange 1,666,000 shares of its Common Stock for all 1,000,000 outstanding shares of the Preferred Stock as the Common Stock had traded above the Threshold Price.

In July 1999, the Company completed an acquisition of substantially all of the Rocky Mountain oil and gas assets of Unocal Corporation for 5.8 million shares of common stock and $5 million in cash.

On March 1, 1991, the Board of Directors adopted a Rights Plan designed to help assure that all stockholders receive fair and equal treatment in the event of a hostile attempt to take over the Company, and to help guard against abusive takeover tactics. The Board of Directors declared a dividend of one preferred share purchase right (a "Right") for each outstanding share of Common Stock. The dividend was distributed on March 15, 1991 to the shareholders of record on that date. As of March 1, 2001, the Board of Directors amended and restated the Rights Plan. Each Right entitles the registered holder to purchase, for the $120 per share exercise price, shares of Common Stock or other securities of the Company (or, under certain circumstances, of the acquiring person) worth twice the per share exercise price of the Right.

The Rights will be exercisable only if a person or group acquires 15% or more of the Company's Common Stock or announces a tender offer which would result in ownership by a person or group of 15% or more of the Common Stock. The date on which the above occurs is to be known as the "Distribution Date". The Rights will expire on March 1, 2011, unless extended or redeemed earlier by the Company.

At the time the Rights dividend was declared, the Board of Directors further authorized the issuance of one Right with respect to each share of the Company's Common Stock that shall become outstanding between March 15, 1991 and the earlier of the Distribution Date or the expiration or redemption of the Rights. Until the Distribution Date occurs, the certificates representing shares of the Company's Common Stock also evidence the Rights. Following the Distribution Date, the Rights will be evidenced by separate certificates.

The provisions described above may tend to deter any potential unsolicited tender offers or other efforts to obtain control of the Company that are not approved by the Board of Directors and thereby deprive the stockholders of opportunities to sell shares of the Company's Common Stock at prices higher than the prevailing market price. On the other hand, these provisions will tend to assure continuity of management and corporate policies and to induce any person seeking control of the Company or a business combination with the Company to negotiate on terms acceptable to the then elected Board of Directors.

ITEM 6. *Selected Financial Data*

The following tables set forth selected financial information for the Company for each of the years shown.

The Company's historical results of operations have been materially affected by the substantial increase in the Company's size as a result of the Stellarton Acquisition in January 2001, the Unocal Acquisition in July 1999, the Genesis Acquisition in October 1997, the Presidio Acquisition in December 1996, and the KNPC Acquisition in January 1996. (See Note 3 to Notes to Consolidated Financial Statements of the Company included elsewhere herein.)

	Years Ended December 31,				
	2001	2000	1999	1998	1997
	(In thousands, except per share amounts)				
Revenues	$326,324	$ 253,910	$123,411	$ 89,939	$ 93,175
Net income (loss) attributable to common stock	69,503	65,703	5,007	(45,233)	6,860
Weighted average number of common shares outstanding					
Basic	38,943	36,664	32,228	29,251	25,110
Diluted	40,227	37,897	32,466	29,251	26,407
Net income (loss) per common share					
Basic	1.78	1.79	.16	(1.55)	.27
Diluted	1.73	1.76	.15	(1.55)	.26
Total assets	844,975	629,535	536,299	441,882	450,926
Long-term debt, net of current maturities	120,570	54,000	81,000	55,000	23,000
Other Financial Data:					
EBITDAX(1)	227,796	177,643	74,438	49,348	69,716
Net cash provided by operating activities before changes in working capital(1)	192,712	159,956	59,821	34,404	59,652
Net cash provided by operating activities	207,900	132,958	38,857	60,100	47,600
Net cash used in investing activities	(276,987)	(117,738)	(54,999)	(89,634)	(86,672)
Net cash provided by (used in) financing activities	66,975	(10,196)	25,982	25,667	25,105

(1) EBITDAX reflects income before income taxes, plus interest expense, depreciation, depletion and amortization expense, exploration costs and impairments of leasehold costs. EBITDAX and cash flows from operating activities before changes in working capital are not measures determined pursuant to generally accepted accounting principles ("GAAP") and are not intended to be used in lieu of GAAP presentations of net income or cash flows from operating activities. EBITDAX for 1998 excludes $51.3 million for impairment of gas and oil properties, which were non-cash charges. EBITDAX for 2001 excludes the cumulative effect of the change in accounting principle.

The following tables set forth selected information for the Company's gas and oil sales volumes and proved reserves for each of the years shown.

	Years Ended December 31,				
	2001	2000	1999	1998	1997
Volumes sold:					
Gas (Mmcf)	63,824	51,199	40,514	35,887	31,842
Oil (MBbls)	881	773	910	1,027	1,159
Natural Gas Liquids (MBbls)	1,217	1,074	535	—	—
Proved reserves at period end:					
Gas (Mmcf)	641,579	535,373	445,933	372,022	347,104
Oil (MBbls)	6,647	6,116	6,735	5,682	7,227
Natural Gas Liquids (MBbls)	8,360	5,077	6,266	—	—

ITEM 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

Critical Accounting Policies and Estimates

The discussion and analysis of the Company's financial condition and results of operations was based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note 2 to our consolidated financial statements. In response to SEC Release No. 33-8040, "Cautionary Advise Regarding Disclosure About Critical Accounting Policies," we have identified certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. We analyze our estimates, including those related to oil and gas revenues, bad debts, oil and gas properties, marketable securities, income taxes, derivatives, contingencies and litigation, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of the Company's financial statements:

Successful Efforts Method of Accounting

The Company accounts for its natural gas and crude oil exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Gas and oil lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for gas and oil leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver gas and oil in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature and an allocation of costs is required to properly account for the results. Delineation seismic incurred to select development locations within an oil and gas field is typically considered a development cost and capitalized but often these seismic programs extend beyond the reserve area considered proved and management must estimate the portion of the seismic costs to expense. The evaluation of gas and oil leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The successful efforts method of accounting can have a significant impact on the operational results reported when the Company is entering a new exploratory area in hopes of finding a gas and oil field that will be the focus of future development drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial which will result in additional exploration expenses when incurred.

Reserve Estimates

The Company's estimates of gas and oil reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of gas and oil that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable gas and oil reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future gas and oil prices, future operating costs, severance taxes, development costs and workover gas costs, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to an extent that these reserves may be later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of gas and oil attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected therefrom may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company's gas and oil properties and/or the rate of depletion of the gas and oil properties. Actual production, revenues and expenditures with respect to the Company's reserves will likely vary from estimates, and such variances may be material.

Impairment of Gas and Oil Properties

The Company reviews its gas and oil properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. The Company estimates the expected future cash flows of its gas and oil properties and compares such future cash flows to the carrying amount of the gas and oil properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the gas and oil properties to their fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected. There were no impairments of gas and oil properties in 2001, 2000 or 1999.

Given the complexities associated with gas and oil reserve estimates and the history of price volatility in the gas and oil markets, events may arise that would require the Company to record an impairment of the recorded book values associated with gas and oil properties. In 1998, the Company recognized an impairment of $51.3 million primarily as a result of the market prices in effect at that time and there can be no assurance that impairments will not be required in the future.

Results of Operations

The Company's results of operations were favorably impacted in 2001, 2000 and 1999 due to the acquisition of Stellarton in January 2001 and the mid-1999 acquisition of properties and a gas processing plant from Unocal. These acquisitions, continued successful drilling results and increased cash flows which resulted from higher production and commodity prices in 2001 and 2000 contributed significantly to the operating results for these periods.

Revenues

During 2001, revenues from gas, oil and natural gas liquids production increased 26% to $274.0 million, as compared to $217.0 million in 2000. This increase was the result of (i) an increase in average gas prices received by the Company from $3.46 per Mcf in 2000 to $3.71 per Mcf in 2001, which increased revenues $16.0 million, (ii) a decrease in average oil and natural gas liquids prices received from $21.49 to $17.86 which decreased revenues $7.6 million, (iii) gas sales volumes increased by 25% to 63.8 Bcf which increased revenues by $43.7 million, and (iv) an increase in oil and natural gas liquids sales volumes of 14% to 2.1 million barrels, which increased revenues by $4.9 million.

Revenues in 2001 were also impacted by cash gains realized from hedging activities. The NYMEX collar and swap transactions considered effective hedges and settled in 2001, resulted in cash gains of $15.9 million, which were included in gas and oil sales. At December 31, 2001, the Company had no open hedge or derivative positions. There was no material hedging activity in 1999 or 2000.

The revenues contributed by the Stellarton transaction for the period subsequent to the closing date of January 12, 2001 were $30.1 million.

During 2000, revenues from gas, oil and natural gas liquids production increased 108% to $217.0 million, as compared to $104.4 million in 1999. Such increase was the result of an increase in (i) average gas prices received by the Company from $2.04 per Mcf in 1999 to $3.46 per Mcf in 2000, which increased revenues $72.7 million, (ii) average oil and natural gas liquids prices received from $15.20 to $21.49 which increased revenues $11.6 million, (iii) gas sales volumes increased by 26% to 51.2 Bcf which increased revenues by $21.8 million (due primarily to the Unocal Acquisition and to successful drilling results), and (iv) oil and natural gas liquids sales volumes of 28% to 1.8 million barrels, which increased revenues by $6.5 million due primarily to the impact of a full year's operations from the Unocal Acquisition.

The following table reflects the Company's revenues, average prices received for gas and oil, and amount of gas and oil production in each of the years shown:

	Years Ended December 31,		
	2001	2000	1999
		(In thousands)	
Revenues:			
Natural gas sales	$236,551	$177,267	$ 82,479
Crude oil sales	20,350	21,686	15,443
Natural gas liquids	17,130	18,015	6,509
Gathering and processing	23,245	18,283	11,968
Marketing and trading, net	1,891	5,841	(786)
Drilling	14,828	11,472	5,645
Gain on sale of property	10,078	—	—
Interest income and other	2,251	1,346	2,153
Total revenues	$326,324	$253,910	$123,411
Net income attributable to common stock	$ 69,503	$ 65,703	$ 5,007

	Years Ended December 31,		
	2001	2000	1999
Natural gas production sold (Mmcf)	63,824	51,199	40,514
Crude oil production (Mbbls)	881	773	910
Natural gas liquid production (Mbbls)	1,217	1,074	535
Average natural gas sales price ($/Mcf)	$ 3.71	$ 3.46	$ 2.04
Average crude oil sales price ($/Bbl)	$ 23.09	$ 28.05	$ 16.98
Average natural gas liquid sales price ($/Bbl)	$ 14.07	$ 16.77	$ 12.16

Gathering and processing revenue increased 27% to $23.2 million as compared to $18.3 million in 2000. In 2000, revenue increased 53% to $18.3 million, as compared to $12.0 million in 1999. In November 2000, certain gathering and processing assets were distributed to the Company from Wildhorse Energy Partners, LLC ("Wildhorse"). Incremental revenues were recognized in 2001 as a result of the 100% ownership of these gathering and processing assets which previously were 45% owned by the Company through the Wildhorse partnership. A number of non-strategic gathering and processing assets were sold throughout 2001. Gathering and processing revenue will be impacted in 2002 as a result of these dispositions. TBI Field Services, Inc. ("TBIFS") was formed as a wholly-owned subsidiary of Tom Brown, Inc. to administer the gathering and processing assets. Incremental volumes gathered by TBIFS from the Wind River Basin where the Company has significant production base also contributed to the increase in revenues.

Net marketing and trading income increased from a net loss in 1999 to a profitable gross margin of $5.8 million in 2000 and $1.9 million in 2001. This was attributable to (i) a general increase in the Company's natural gas marketing operations, (ii) an increase in the volume of gas marketed for third parties and (iii) lower transportation rates. In 2000, the Company benefited from certain term and spot natural gas sales at more favorable rates than were available in the 2001 market.

Drilling revenue associated with the Company's wholly-owned subsidiary, Sauer, increased 29% in 2001 to $14.8 million and 103% to $11.5 million in 2000 due to higher rig utilization rates and increased day rates resulting from the general increase in activity within the oil and gas industry in 2001 and 2000.

Costs and Expenses

Expenses related to gas and oil production increased 26% from 2000 to 2001 due primarily to the Stellarton Acquisition and increased production levels in 2001. On an Mcfe basis, gas and oil production costs remained relatively flat at $.42 in 2001 and $.41 in 2000.

Expenses related to gas and oil production increased 38% from 1999 to 2000 due primarily to the acquisition of gas and oil properties and a cyrogenic natural gas processing plant in July 1999 from Unocal. On an Mcfe basis, gas and oil production costs increased to $.41 in 2000 from $.38 in 1999, due primarily to the cost of operating the plant.

Taxes on gas and oil production decreased by 5% (or $1.1 million) in 2001 despite a 26% (or $57 million) increase in revenue from gas, oil and natural gas liquids for 2001. This relationship resulted from the inclusion of $30.1 million of Canadian revenues in the 2001 results which are not subject to severance and other taxes typically incurred in the United States. Additionally, $15.9 million realized on the natural gas hedge transactions was included in gas and oil sales in 2001 which is not subject to production related taxes. The Company also obtained a refund in 2001 of a portion of the production taxes paid in prior years' which reduced the expenses reported.

Taxes on gas and oil production increased 123% in 2000 directly related to the increase in gas, oil and natural gas liquids sales in these periods. The taxes for 1999 and 2000 remained relatively constant as a percentage of sales.

Depreciation, depletion and amortization increased $24.0 million in 2001 as compared to 2000. Approximately $14.1 million of this increase was associated with the depletion recorded on the Stellarton assets acquired in January 2001. The production increase of 9% on a Mcfe basis on the domestic properties for

2001 also increased depreciation, depletion and amortization. To a lessor extent, the increased cost associated with finding new proved reserves increased the depletion rate in 2001. Depreciation, depletion and amortization increased $6.2 million in 2000, as compared to 1999. The increase was primarily due to increased production, partially offset by a 9% increase in reserve quantities resulting from upward revisions in the estimated reserve quantities recognized in 2000.

Gathering and processing costs principally represents gas purchased in conjunction with the gas gathering operation to replace gas physically lost in the transmission process and all other costs associated with operating and maintaining the gathering and processing systems. This expense increased in 2001 and the last month of 2000, due to the 100% ownership of the gathering operations after the Wildhorse distribution, increased activity in the gathering operations and as a result of the increase in the commodity price for natural gas during this period.

Expenses associated with the Company's exploration activities were $34.2 million, $11.0 million and $10.0 million for the years 2001, 2000 and 1999, respectively. The Company's increased exploration efforts in 2001 resulted in increased dryhole costs and seismic related expenses. Capital expenditures of $358.1 million were incurred in 2001 which included $95 million associated with the Stellarton acquisition. The 2001 exploration, development and land related expenditures were $242 million, an increase of 121% in comparison to 2000. In 1999, the Unocal acquisition was completed at a cost of $60.9 million and the exploration, development and land related expenditures were $47.4 million.

General and administrative expenses have increased from year to year as a result of the Company's increased level of operations. On an Mcfe basis, general and administrative expenses were $.30, $.19, and $.19 for the years 2001, 2000 and 1999, respectively. Included in the expenses for 2001 was a $5.3 million ($.07 per Mcfe) pre-tax charge recorded in the first quarter of 2001 associated with the retirement of Donald L. Evans, previously Tom Brown, Inc.'s Chairman and CEO. Mr. Evans received a $1.5 million retirement payment and the Company recognized a $3.8 million non-cash charge in conjunction with the acceleration of Mr. Evans' stock options. General and administrative expenses related to Stellarton contributed $2.5 million ($.03 per Mcfe) to the increase from 2000. Expenses also increased due to the addition of personnel necessary to accomplish the increase in the capital expenditure programs.

Interest expense increased $1.4 million in 2001 due to the increase in debt associated with financing the Stellarton transaction. The increased debt levels in 2001 resulting from this transaction benefited from the general reduction in interest rates during this period. The Company's effective interest rate under its credit facility was 7.9% at December 31, 2000 and 4.1% at December 31, 2001. Interest expense increased $.4 million in 2000 to $6.0 million as compared to $5.6 million in 1999 due to an increase in interest rates in 2000.

The Company recorded income tax provisions of $38.1 million, $39.8 million and $4.3 million in 2001, 2000, and 1999, respectively, resulting in effective tax rates of 36.1%, 37.4% and 38.9%, respectively. At December 31, 2001, the Company has a net operating loss carryforward available for U.S. Federal tax purposes of $18.7 million and a net operating loss carryforward available to reduce future Canadian federal income taxes of $700,000 ($1,084,000 CDN). Additionally, statutory depletion carryforwards of approximately $6.2 million and $5.2 million of alternative minimum tax credit carryforwards are available in the U.S. to offset future taxes. Based upon the operating results for 2001 and the present economic environment for the oil and gas industry, the Company believes that it will generate sufficient taxable income to utilize these carryforwards.

Capital Resources and Liquidity

Growth and Acquisitions

The Company continues to pursue opportunities which will add value by increasing its reserve base and presence in significant natural gas areas, and further developing the Company's ability to control and market the production of natural gas. As the Company continues to evaluate potential acquisitions and property development opportunities, it will benefit from its financing flexibility and the leverage potential of the

Company's overall capital structure. The Company does not conduct its business through special purpose entities or have any exposure to off-balance sheet financing arrangements.

Capital and Exploration Expenditures

The Company's capital and exploration expenditures and sources of financing for the years ended December 31, 2001, 2000 and 1999 are as follows:

	2001	2000	1999
		(In millions)	
CAPITAL AND EXPLORATION EXPENDITURES:			
ACQUISITIONS:			
Stellarton	$ 95.0	$ —	$ —
Sauer Drilling Company	5.2	2.7	1.4
Unocal	—	—	60.9
Other Rocky Mountain Assets	3.3	17.1	8.2
Other	—	—	2.5
Exploration costs	56.0	18.4	12.0
Development costs	163.2	74.4	33.2
Acreage	22.6	16.8	2.5
Gas gathering and processing	9.3	16.3	2.7
Other	3.5	4.8	1.7
	$358.1	$150.5	$125.1
FINANCING SOURCES:			
Common stock issued	$ 11.2	$ 17.7	$ 65.2
Net long term bank debt	55.8	(27.0)	26.0
Debt assumed on Stellarton transaction	16.8	—	—
Advances from gas purchasers	—	—	(24.5)
Proceeds from sale of assets	52.4	9.7	2.6
Cash flow from operations before changes in working capital	192.7	160.0	59.8
Working capital and other	29.2	(9.9)	(4.0)
	$358.1	$150.5	$125.1

The Company anticipates capital and exploration expenditures between $115 to $125 million in 2002, $104 to $113 million allocated to exploration and development activity. The timing of most of the Company's capital expenditures is discretionary and there are no material long-term commitments associated with the Company's capital expenditure plans. Consequently, the Company is able to adjust the level of its capital expenditures as circumstances warrant. The level of capital expenditures by the Company will vary in future periods depending on energy market conditions and other related economic factors.

Historically, the Company has funded capital expenditures and working capital requirements with both internally generated cash, borrowings and stock transactions. Net cash flow provided by operating activities after changes in working capital was $207.9 million for 2001 as compared to $133.0 million and $38.9 million in 2000 and 1999, respectively. Net cash flow in 1999 was impacted by the receipt of $24.5 million from gas purchasers as advances in 1998. In July 1999, the Company completed an acquisition of substantially all of the Rocky Mountain oil and gas assets of Unocal Corporation for 5.8 million shares of common stock and $5 million in cash.

Property Sales

In 2001, $52.4 million in cash proceeds were derived from property sales. In May 2001, the Company sold its interest in oil and gas properties located in Oklahoma. These properties had a net book basis of $14.4 million. This transaction resulted in a gain of $10.1 million with net cash proceeds of $24.5 million. Cash proceeds of $24 million were also realized in conjunction with several sales transactions in 2001 associated with the disposition of gathering and processing facilities received in the Wildhorse distribution in November 2000. As the systems sold were non-strategic to the Company's operations and these divestitures were anticipated as part of the Wildhorse integration process, the proceeds derived on these transactions were recorded as a reduction to the investment in the gathering assets.

Advance from Gas Purchasers

The Company sold 35 Mmbtu per day of gas for 1999 delivery, but was paid $24.3 million for the gas in the fourth quarter of 1998 as described within the Notes to the financial statements. The proceeds from the sale were used to repay bank debt.

Debt

Contractual Obligations

In addition to the bank credit facility discussed in the following note, the Company had various other contractual obligations as of December 31, 2001. The following table lists the Company's significant liabilities at December 31, 2001 including the credit facility:

	Payments Due by Period				
Contractual Obligations	Less than 1 year	2-3 Years	4-5 Years	After 5 Years	Total
			(In thousands)		
Bank credit facility	$ —	$25,570	$ 95,000	$ —	$120,570
Operating leases	1,502	1,544	—	—	3,046
Transportation commitments	5,176	6,706	2,425	596	14,903
Processing commitment	2,268	4,536	4,536	11,340	22,680
Drilling obligation	4,841	10,372	—	—	15,213
Total contractual cash obligations	$13,787	$48,728	$101,961	$11,936	$176,412

The Company leases its corporate offices in Denver, Colorado under the terms of an operating lease, which expires in January 2004. Yearly payments under the lease are approximately $900,000 net of sublease income. The office lease in Midland, Texas represents a commitment of $215,000 per year through December 2003 and the office lease in Calgary, Alberta expires in August 2004 at a rate of $152,000 per year. The remaining operating lease commitments represent equipment leases, which expire during 2002 through 2004.

The Company has entered into various firm transportation commitments for approximately 60 MMcf of gross gas sales per day as of December 31, 2001. The majority of these contracts expire in 2002 and 2003.

At December 31, 2001, the Company had entered into an agreement with a third party to process its gas production from the White River Dome coal bed methane project in the Piceance Basin. Under the terms of this agreement, the Company is obligated to pay the third party $189,000 per month over the ten year term to cover the fixed operating costs of the plant and provide for a recovery of the plant investment to the third party. The Company is also obligated to reimburse the third party for certain variable expenses associated with the volumes processed through the plant and for compression made available to the Company. Under certain circumstances, the Company has the right but not the obligation to purchase the processing facility from the third party during the term of this agreement.

To assure the availability of a drilling rig in conjunction with an exploration program in West Texas, the Company entered into a two-year commitment with a drilling contractor in 2001. The rig became available on March 1, 2002 after which a 90-day period is allowed under the terms of this agreement to mobilize the rig and commence the two-year drilling obligation. Under the terms of this arrangement, the Company is required to pay a daywork rate of $20,100/day during drilling operations, $16,700/day for rig moves and a special standby rate of $6,000/day during the initial 90-day commencement period.

Bank Credit Facility

On June 30, 2000, the Company entered into a new $125 million credit facility (the "New Credit Facility") that was to mature in June 2003. Under the terms of the New Credit Facility, the borrowing base was established at $225 million.

On March 20, 2001, as part of the final financing of the Stellarton acquisition, the Company repaid and cancelled its previous $125 million revolving credit facility and entered into a new $225 million credit facility (the "Global Credit Facility"). The Global Credit Facility is comprised of: a $75 million line of credit in the U.S. and a $55 million line of credit in Canada which both mature in March 2004, and a $95 million five-year term loan in Canada. The borrowing base under the Global Credit Facility was set at $300 million. The Global Credit Facility allows the lenders one scheduled redetermination of the borrowing base each December. In addition, the lenders may elect to require one unscheduled redetermination in the event the borrowing base utilization exceeds 50% of the borrowing base at any time for a period of 15 consecutive business days. At December 31, 2001, the Company had borrowings outstanding under the Global Credit Facility totaling $120.6 million or 40% of the borrowing base at an average interest rate of 4. 1%. The amount available for borrowing under the Global Credit Facility at December 31, 2001 was $104.4 million.

Borrowings under the Global Credit Facility are unsecured and bear interest, at the election of the Company, at a rate equal to (i) the greater of the global administrative agents prime rate or the federal funds effective rate plus an applicable margin, (ii) adjusted LIBOR for Eurodollar loans plus applicable margin, or (iii) Bankers' Acceptances plus applicable margin for Canadian dollar loans. Interest on amounts outstanding under the Global Credit Facility is due on the last day of each quarter for prime based loans, and in the case of Eurodollar loans with an interest period of more than three months, interest is due at the end of each three month interval.

The Global Credit Facility contains certain financial covenants and other restrictions similar to the limitations associated with the cancelled credit facility. The financial covenants of the Global Credit Facility require the Company to maintain a minimum consolidated tangible net worth of not less than $350 million (adjusted upward by 50% of quarterly net income and 50% of the net cash proceeds of any stock offering) and the Company will not permit its ratio of (i) indebtedness to (ii) earnings before interest expense, State and Federal taxes and depreciation, depletion and amortization expense and exploration expense to be more than 3.0 to 1.0 as calculated at the end of each fiscal quarter. The Company was in compliance with all covenants during 2001 and at December 31, 2001.

Markets and Prices

The Company's revenues and associated cash flows are significantly impacted by changes in gas and oil prices. All of the Company's gas and oil production is currently market sensitive as none of the Company's gas and oil production has been presold at contractually specified prices. During 2001, the average prices received for gas and oil by the Company were $3.71 per Mcf and $17.86 per barrel, respectively, as compared to $3.46 Mcf and $21.49 per barrel in 2000 and $2.04 per Mcf and $15.20 per barrel in 1999.

In December 2000, the Company believed that the pricing environment provided a strategic opportunity to significantly reduce the price risk on a portion of the Company's production and decided to implement a hedging program. Accordingly, the Company has entered into natural gas and crude oil futures contracts with counter parties to hedge the price risk associated with a portion of its production. These derivatives are not held for trading purposes. To the extent that changes occur in the market prices of natural gas and oil, the Company is exposed to market risk on these open contracts. This market risk exposure is generally offset by the gain or loss recognized upon the ultimate sale of the commodity hedged.

In December 2000, the Company entered into several costless collar arrangements (put and call options) to hedge approximately 40% of the Company's expected 2001 U.S. gas production. These positions were open as of January 1, 2001 when the Company adopted SFAS 133 and SFAS 138. Based upon the natural gas index pricing strip in effect as of January 1, 2001, the impact of these hedges at adoption resulted in a charge to Other Comprehensive Loss of $4.5 million (net of the deferred tax benefit of $2.6 million) and the recognition of a derivative liability of $7.1 million. As of December 31, 2001, the Company had no outstanding cash flow hedges. The Company received cash settlements of $15.4 million in 2001, which were recognized as increases in gas and oil sales.

The Company also entered into natural gas basis swaps covering essentially the same time period of the natural gas costless collars. These transactions were executed in December, 2000 with settlement periods in 2001. Under SFAS 133, these basis swaps did not qualify for hedge accounting. Accordingly, upon adoption of SFAS 133, these basis swaps resulted in the recognition of derivative gains of $2.0 million, recorded as a cumulative effect of a change in accounting principle, (net of the deferred tax liability of $1.2 million) and a derivative asset of $3.2 million. A $.9 million gain was recognized in conjunction with the change in the value of these contracts in the year ended December 31, 2001. Cash receipts of $4.1 million were received during this period. No basis swaps were outstanding at December 31, 2001.

In August 2001, the Company entered into NYMEX based swaps for the September and October 2001 contract periods. Basis swaps were purchased on these quantities to correlate the volumes back to markets where the Company actually delivers gas. Cash settlements of $2.0 million were received on these contracts which increased gas and oil sales.

In October 2001, the Company entered into NYMEX based swaps for the November 2001 contract period. Basis swaps were purchased on these quantities to correlate the volumes back to markets where the Company actually delivers gas. A cash settlement of $1.5 million was paid on the contracts which decreased gas and oil sales.

At December 31, 2001, there were no collars or other forms of hedging transactions in place.

Forward-Looking Statements and Risk

Certain statements in this report, including statements of the future plans, objectives, and expected performance of the Company, are forward-looking statements that are dependent on certain events, risks and uncertainties that may be outside the Company's control which could cause actual results to differ materially from those anticipated. Some of these include, but are not limited to, economic and competitive conditions, inflation rates, legislative and regulatory changes, financial market conditions, political and economic uncertainties, future business decisions, and other uncertainties, all of which are difficult to predict.

There are numerous uncertainties inherent in estimating quantities of proven oil and gas reserves and in projecting future rates of production and timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates. The drilling of exploratory wells can involve significant risks including those related to timing, success rates and cost overruns. Lease and rig availability, complex geology and other factors can affect these risks. Future oil and gas prices also could affect results of operations and cash flows.

Donald L. Evans Resignation

Effective January 19, 2001, Donald L. Evans resigned as the Company's Chairman and Chief Executive Officer to become the United States Secretary of Commerce. Mr. Evans received a retirement payment of $1.5 million in cash. In addition, the Company accelerated the vesting of his outstanding stock options resulting in a non-cash, pre-tax charge to earnings of approximately $3.8 million. Both the retirement payment and the non-cash charge for the acceleration of the stock options were recognized by the Company in the first quarter of 2001.

ITEM 7A. *Quantitative and Qualitative Disclosure About Market Risk*

The Company utilizes various financial instruments which inherently have some degree of market risk. The primary sources of market risk include fluctuations in commodity prices and interest rate fluctuations. The Company does not conduct its business through any special purpose entities or have any exposure to off-balance sheet financing arrangements.

Price Fluctuations

The Company's results of operations are highly dependent upon the prices received for oil and natural gas production. Accordingly, in order to increase the financial flexibility and to protect the Company against commodity price fluctuations, the Company may, from time to time in the ordinary course of business, enter into non-speculative hedge arrangements, commodity swap agreements, forward sale contracts, commodity futures, options and other similar agreements relating to natural gas and crude oil.

Derivative Financial Instruments

Financial instruments designated as hedges are accounted for on the accrual basis with gains and losses being recognized based on the type of contract and exposure being hedged. Gains and losses on natural gas and crude oil swaps designated as hedges of anticipated transactions, including accrued gains or losses upon maturity or termination of the contract, are deferred and recognized in income when the associated hedged commodities are produced. In order for natural gas and crude oil swaps to qualify as a hedge of an anticipated transaction, the derivative contract must identify the expected date of the transaction, the commodity involved, and the expected quantity to be purchased or sold among other requirements. In the event that a hedged transaction does not occur, future gains and losses, including termination gains or losses, are included in the income statement when incurred.

In June 1998, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. It also requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. SFAS 133 is effective for all fiscal quarters of fiscal years beginning after June 15, 2000. In June 2000, the FASB issued SFAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities". This pronouncement amended portions of SFAS 133 and was adopted by the Company with SFAS 133 effective January 1, 2001.

SFAS 133, in part, allows special hedge accounting for cash flow hedges and provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of Other Comprehensive Income and be reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings.

Interest Rate Risk

At December 31, 2001, the Company had $120.6 million outstanding under the Global Credit Facility at an average interest rate of 4.1%. Borrowings under the Global Credit Facility bear interest, at the election of the Company, at (i) the greater of the global administrative agents prime rate or the federal funds effective rate, plus an applicable margin, (ii) adjusted LIBOR for Eurodollar loans plus applicable margin, or (iii) Bankers' Acceptance plus applicable margin for Canadian dollar loans. As a result, the Company's annual interest cost in 2002 will fluctuate based on short-term interest rates. Assuming no change in the amount outstanding during 2002, the impact on interest expense of a ten percent change in the average interest rate would be approximately $.5 million. As the interest rate is variable and is reflective of current market conditions, the carrying value of the Global Credit Facility approximates the fair value.

ITEM 8. *Financial Statements and Supplementary Data*

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors and Stockholders of Tom Brown, Inc.:

We have audited the accompanying consolidated balance sheets of Tom Brown, Inc. (a Delaware corporation) and subsidiaries as of December 31, 2001 and 2000,and the related consolidated statements of operations, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Tom Brown, Inc. and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Notes 2 and 10 to the consolidated financial statements, on January 1, 2001, the Company changed its method of accounting for derivative instruments and hedging activities.

ARTHUR ANDERSEN LLP

Denver, Colorado
February 27, 2002

TOM BROWN, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2001	December 31, 2000
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 15,196	$ 17,534
Accounts receivable	63,745	95,878
Inventories	1,689	521
Other	2,332	2,307
Total current assets	82,962	116,240
PROPERTY AND EQUIPMENT, AT COST:		
Gas and oil properties, successful efforts method of accounting	849,628	575,991
Gas gathering and processing and other plant	89,343	81,873
Other	33,689	28,746
Total property and equipment	972,660	686,610
Less: Accumulated depreciation, depletion and amortization	234,134	176,848
Net property and equipment	738,526	509,762
OTHER ASSETS:		
Goodwill, net	18,125	—
Other assets	5,362	3,533
	$844,975	$629,535
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 59,172	$ 55,982
Accrued expenses	12,512	22,119
Total current liabilities	71,684	78,101
BANK DEBT	120,570	54,000
DEFERRED INCOME TAXES	75,194	5,475
OTHER NON-CURRENT LIABILITIES	2,299	3,066
COMMITMENTS AND CONTINGENCIES (Note 13)		
STOCKHOLDERS' EQUITY:		
Convertible preferred stock, $.10 par value Authorized 2,500,000 shares;		
Common Stock, $.10 par value Authorized 55,000,000 shares; Outstanding 39,127,649 and 38,351,860 shares, respectively	3,913	3,835
Additional paid-in capital	534,790	516,911
Retained earnings (accumulated deficit)	37,855	(31,648)
Accumulated other comprehensive loss	(1,330)	(205)
Total stockholders' equity	575,228	488,893
	$844,975	$629,535

See accompanying notes to consolidated financial statements.

TOM BROWN, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2001	2000	1999
	(In thousands, except per share amounts)		
REVENUES:			
Gas, oil and natural gas liquids sales	$274,031	$216,968	$104,431
Gathering and processing	23,245	18,283	11,968
Marketing and trading, net	1,891	5,841	(786)
Drilling	14,828	11,472	5,645
Gain on sale of property	10,078	—	1,265
Change in derivative fair value	897	—	—
Interest income and other	1,354	1,346	888
Total revenues	326,324	253,910	123,411
COSTS AND EXPENSES:			
Gas and oil production	32,060	25,488	18,446
Taxes on gas and oil production	21,020	22,105	9,934
Gathering and processing costs	10,855	7,212	5,853
Drilling operations	11,851	9,715	5,237
Exploration costs	34,195	11,001	10,013
Impairments of leasehold costs	5,236	3,900	3,600
General and administrative	22,742	11,614	9,203
Depreciation, depletion and amortization	74,371	50,417	44,215
Interest expense and other	8,390	6,100	5,860
Total costs and expenses	220,720	147,552	112,361
Income before income taxes and cumulative effect of change in accounting principle	105,604	106,358	11,050
Income tax provision			
Current	(1,200)	(1,968)	(903)
Deferred	(36,927)	(37,812)	(3,390)
Net income before cumulative effect of change in accounting principle	67,477	66,578	6,757
Cumulative effect of change in accounting principle	2,026	—	—
Net income	69,503	66,578	6,757
Preferred stock dividends	—	(875)	(1,750)
Net income attributable to common stock	$ 69,503	$ 65,703	$ 5,007
Weighted average number of common shares outstanding:			
Basic	38,943	36,664	32,228
Diluted	40,227	37,897	32,466
Earnings per common share — Basic:			
Income before cumulative effect of change in accounting principle	$ 1.73	$ 1.79	$ .16
Cumulative effect of change in accounting principle	.05	—	—
Net income attributable to common stock	$ 1.78	$ 1.79	$ .16
Earnings per common share — Diluted:			
Income before cumulative effect of change in accounting principle	$ 1.68	$ 1.76	$ .15
Cumulative effect of change in accounting principle	.05	—	—
Net income attributable to common stock	$ 1.73	$ 1.76	$ .15

See accompanying notes to consolidated financial statements.

TOM BROWN, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Preferred Stock		Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				
					(In thousands)			
Balance as of December 31, 1998	1,000	$ 100	29,260	$2,926	$431,082	$(102,358)	$ —	$331,750
Stock options exercised	—	—	248	25	1,107	—	—	1,132
Income tax benefit of stock options exercised	—	—	—	—	600	—	—	600
Common stock issuance	—	—	5,800	580	62,935	—	—	63,515
Unrealized gain on marketable securities	—	—	—	—	—	—	93	93
Net income	—	—	—	—	—	6,757	—	6,757
Preferred stock dividends	—	—	—	—	—	(1,750)	—	(1,750)
Balance as of December 31, 1999	1,000	100	35,308	3,531	495,724	(97,351)	93	402,097
Stock options exercised	—	—	1,378	137	17,475	—	—	17,612
Income tax benefit of stock options exercised	—	—	—	—	3,779	—	—	3,779
Unrealized loss on marketable securities	—	—	—	—	—	—	(298)	(298)
Net income	—	—	—	—	—	66,578	—	66,578
Preferred stock dividends	—	—	—	—	—	(875)	—	(875)
Preferred stock conversion	(1,000)	(100)	1,666	167	(67)	—	—	—
Balance as of December 31, 2000	—	—	38,352	3,835	516,911	(31,648)	(205)	488,893
Stock options exercised	—	—	776	78	11,085	—	—	11,163
Income tax benefit of stock options exercised	—	—	—	—	2,897	—	—	2,897
Accelerated vesting of options	—	—	—	—	3,897	—	—	3,897
Comprehensive income (loss):								
Translation loss	—	—	—	—	—	—	(790)	(790)
Cumulative effect of change in accounting principle (net of tax)	—	—	—	—	—	—	(4,449)	(4,449)
Change in fair value of derivative hedging instruments	—	—	—	—	—	—	14,466	14,466
Hedge settlements reclassified to income (net of tax)	—	—	—	—	—	—	(10,017)	(10,017)
Unrealized loss on marketable securities	—	—	—	—	—	—	(335)	(335)
Net income	—	—	—	—	—	69,503	—	69,503
Total comprehensive income	—	—	—	—	—	69,503	(1,125)	68,378
Balance as of December 31, 2001	—	$ —	39,128	$3,913	$534,790	$ 37,855	$ (1,330)	$575,228

See accompanying notes to consolidated financial statements.

TOM BROWN, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2001	2000	1999
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 69,503	$ 66,578	$ 6,757
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	74,371	50,417	44,215
Gain on sales of assets	(10,078)	—	(1,265)
Accelerated vesting of options	3,897	—	—
Deferred tax provision	36,927	37,812	3,390
Dry hole costs	15,779	1,249	3,124
Impairments of leasehold costs	5,236	3,900	3,600
Changes in operating assets and liabilities, net of the effects from the purchase of Stellarton:			
(Increase) decrease in accounts receivable	43,520	(42,232)	(19,140)
(Increase) decrease in inventories	(109)	307	(296)
(Increase) decrease in other current assets	388	(1,541)	(616)
Increase (decrease) in accounts payable and accrued expenses	(28,597)	15,549	22,644
(Increase) decrease in other assets, net	(2,937)	919	973
Advances from gas purchasers	—	—	(24,529)
Net cash provided by operating activities	207,900	132,958	38,857
CASH FLOWS FROM INVESTING ACTIVITIES:			
Proceeds from sales of assets	52,366	9,681	2,573
Capital and exploration expenditures	(244,663)	(140,719)	(56,183)
Acquisition of Stellarton stock	(74,500)	—	—
Direct costs on Stellarton acquisition	(3,107)	—	—
Changes in accounts payable and accrued expenses for capital expenditures	(7,082)	13,300	(1,389)
Net cash used in investing activities	(276,986)	(117,738)	(54,999)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings of long-term bank debt	109,812	20,000	26,000
Repayments of long-term bank debt	(54,000)	(47,000)	—
Preferred stock dividends	—	(875)	(1,750)
Proceeds from exercise of stock options	11,163	17,679	1,732
Net cash provided by (used in) financing activities	66,975	(10,196)	25,982
Effect of exchange rate changes on cash	(227)	—	—
NET CHANGE IN CASH AND CASH EQUIVALENTS	(2,338)	5,024	9,840
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	17,534	12,510	2,670
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 15,196	$ 17,534	$ 12,510
Supplemental disclosures of cash flow information: Cash paid during the year for:			
Interest	$ 7,219	$ 4,941	$ 4,051
Income taxes	7,421	840	—
Supplemental schedule of noncash investing and financing activities: (see Notes 2 and 3)			
Common stock issued as consideration in connection with Unocal Acquisition	$ —	$ —	$ 63,515
Common stock received for outstanding receivable	—	—	700
Debt assumed in Stellarton Acquisition	16,800	—	—

See accompanying notes to consolidated financial statements.

(1) Nature of Operations

Tom Brown, Inc. and its wholly-owned subsidiaries (the "Company") is an independent energy company engaged in the exploration for, and the acquisition, development, marketing, production and sale of, natural gas and crude oil. The Company's industry segments are (i) the exploration for, and the acquisition, development, production, and sale of, natural gas and crude oil, (ii) the marketing, gathering and processing of natural gas, primarily through Retex, Inc. ("Retex"), Wildhorse Energy Partners, L. L. C. ("Wildhorse") and TBI Field Services, Inc. ("TBIFS") and (iii) drilling gas and oil wells, primarily through Sauer Drilling Company ("Sauer"). The Company's operations are conducted in the United States and Canada. The Company's United States operations are presently focused in the Wind River and Green River Basins of Wyoming, the Piceance Basin of Colorado, the Paradox Basin of eastern Utah and western Colorado, the Val Verde Basin of west Texas, the Permian Basin of west Texas and southeastern New Mexico, and east Texas. The Company also, to a lesser extent, conducts exploration and development activities in other areas of the continental United States. The Company expanded its operations in Canada in 2001, establishing western Canada as a core area through the acquisition of Stellarton Energy Corporation ("Stellarton"). This transaction was completed in January 2001. The Canadian operations are focused in the Carrot Creek, Edson and Davey Lake areas of the western sedimentary basin of Alberta.

Wildhorse was originally formed by KN Energy, Inc. ("KNE") and the Company in January 1996. KNE was subsequently acquired by Kinder Morgan Inc. ("KM"). Initially, Wildhorse was owned fifty-five percent (55%) by KNE and forty-five percent (45%) by the Company. The Company dedicated a significant amount of its Rocky Mountain gas reserves to Wildhorse and KNE contributed substantial gas marketing contracts. The Company also transferred a natural gas storage facility in western Colorado to Wildhorse. The principal purpose of Wildhorse was to provide services related to natural gas, natural gas liquids and other natural gas products, including gathering, processing and storage services. In September 1999, Wildhorse assigned 100% of its marketing operations to Retex. Firm transportation contracts were also assigned 55% to KM and 45% to Retex at that time. In November 2000, the remaining gathering and processing assets were distributed to the Company in anticipation of the dissolution of Wildhorse. KM received the storage facility and a cash payment. TBIFS was formed as a wholly-owned subsidiary of Tom Brown, Inc. to administer the gathering and processing assets received in the Wildhorse distribution. In 2001, TBIFS selectively sold many of the gathering and processing facilities received in the Wildhorse asset distribution retaining only those gathering systems considered integral to the Company's operations. The Wind River gathering system was the main system retained.

Substantially all of the Company's production is sold under market-sensitive contracts. The Company's revenue, profitability and future rate of growth are substantially dependent upon the price of, and demand for, oil, natural gas and natural gas liquids. Prices for natural gas, crude oil and natural gas liquids are subject to wide fluctuation in response to relatively minor changes in their supply and demand as well as market uncertainty and a variety of additional factors that are beyond the control of the Company. These factors include the level of consumer product demand, weather conditions, domestic and foreign governmental regulations, the price and availability of alternative fuels, political conditions in foreign countries, the foreign supply of natural gas and oil and the price of foreign imports and overall economic conditions. The Company is affected more by fluctuations in natural gas prices than oil prices because a majority of its production (84 percent in 2001 on a volumetric equivalent basis) is natural gas.

(2) Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation

The accompanying consolidated financial statements include the accounts of the Company. The Company's proportionate share of assets, liabilities, revenues and expenses associated with certain interests in a gas and oil partnership were consolidated within the accompanying financial statements for the periods prior to Wildhorse asset distribution. All significant intercompany accounts and transactions have been eliminated. Certain reclassifications have been made to amounts reported in previous years to conform to the 2001 presentation.

Inventories

Inventories consist of pipe, other production equipment and natural gas placed in storage. Inventories are stated at the lower of cost (principally first-in, first-out) or estimated net realizable value.

Property and Equipment

The Company accounts for its natural gas and crude oil exploration and development activities under the successful efforts method of accounting. Under such method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Gas and oil lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for gas and oil leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

Maintenance and repairs are charged to expense; renewals and betterments are capitalized to the appropriate property and equipment accounts. Upon retirement or disposition of assets, the costs and related accumulated depreciation are removed from the accounts with the resulting gains or losses, if any, reflected in results of operations.

Unproved properties with significant acquisition costs are assessed quarterly on a property-by-property basis and any impairment in value is charged to expense. Unproved properties whose acquisition costs are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive, based on historical experience, is amortized over the average holding period. If the unproved properties are determined to be productive, the related costs are transferred to proved gas and oil properties. Proceeds from sales of partial interests in unproved leases are accounted for as a recovery of cost without recognizing any gain or loss.

The Company reviews its gas and oil properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. The Company estimates the expected future cash flows of its gas and oil properties and compares such future cash flows to the carrying amount of the gas and oil properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected. There were no impairments of gas and oil properties in 2001, 2000 or 1999.

The provision for depreciation, depletion and amortization of oil and gas properties is calculated on a basin-by-basin basis using the unit-of-production method. Included in such calculations are estimated future dismantlement, restoration and abandonment costs, net of estimated salvage values.

Other property and equipment is recorded at cost or estimated fair value upon acquisition and depreciated using the straight-line method based on estimated useful lives.

Natural Gas Revenues

The Company utilizes the accrual method of accounting for natural gas revenues whereby revenues are recognized as the Company's entitlement share of gas is produced based on its working interests in the properties. The Company records a receivable (payable) to the extent it receives less (more) than its proportionate share of gas revenues. Using historical prices, the Company had net gas balancing liabilities of approximately $1.2 million associated with approximately .7 billion cubic feet ("Bcf") of gas at December 31, 2000. At December 31, 2001, the imbalance position was not significant.

Foreign Currency Translation

The functional currency of the Company's Canadian subsidiary is the Canadian dollar. For purposes of consolidation, substantially all assets and liabilities of the Canadian operations are translated into U.S. dollars at exchange rates in effect at the balance sheet dates. Unrealized currency translation adjustments are accumulated as a separate component of accumulated other comprehensive income within stockholders' equity. Income and expense items are translated at average exchange rates during the year. As a result of the change in the Canadian dollar relative to the U.S. dollar, the Company reported a translation loss of $790,000 in 2001.

Derivative Financial Instruments

In order to increase financial flexibility and to protect the Company against commodity price fluctuations, the Company may, from time to time in the ordinary course of business, enter into non-speculative hedge arrangements, commodity swap agreements, forward sale contracts, commodity futures, options and other similar agreements relating to natural gas and crude oil.

In June 1998, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. It also requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. SFAS 133 is effective for all fiscal quarters of fiscal years beginning after June 15, 2000. In June 2000, the FASB issued SFAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities". This pronouncement amended portions of SFAS 133 and was adopted by the Company with SFAS 133 effective January 1, 2001.

SFAS 133, in part, allows special hedge accounting for cash flow hedges and provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of Other Comprehensive Income and be reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings.

Recently Issued Accounting Standards

In June 2001, the FASB issued SFAS No. 141, "Business Combinations," which addresses financial accounting and reporting for business combinations. SFAS No. 141 is effective for all business combinations initiated after June 30, 2001 and for all business combinations accounted for under the purchase method initiated before but completed after June 30, 2001. The adoption of SFAS No. 141 is not expected to have a material impact on the Company's financial position or results of operations.

In June 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets," which addresses, among other things, the financial accounting and reporting for goodwill subsequent to an acquisition. The new standard eliminates the requirement to amortize acquired goodwill; instead, such goodwill shall be reviewed at least annually for impairment. SFAS No. 142 is required to be adopted on January 1, 2002. The Company is analyzing the provisions of SFAS No. 142, and expects that future annual amortization expense will be reduced by approximately $.9 million, but has not yet determined whether the other provisions of SFAS No. 142 will otherwise impact its financial statements upon adoption.

In July 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations". SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for the recorded amount or incurs a gain or loss upon settlement. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. The Company will adopt SFAS No. 143 on January 1, 2003, but has not yet quantified the effects of adopting SFAS No. 143 on its financial position or results of operations.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". SFAS No. 144 supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of". SFAS No. 121 did not address the accounting for a segment of a business accounted for as a discontinued operation which resulted in two accounting models for long-lived assets to be disposed of. SFAS No. 144 establishes a single accounting model for long-lived assets to be disposed of by sale and requires that those long-lived assets be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations. SFAS No. 144 is effective for fiscal years beginning after December 15, 2001. The Company will adopt SFAS No. 144 on January 1, 2002, and anticipates no impact on its financial position or results of operations.

Income Taxes

The Company provides for income taxes using the liability method under which deferred income taxes are recognized for the tax consequences of "temporary differences" by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The effect on deferred taxes of a change in tax laws or tax rates is recognized in income in the period such changes are enacted.

Stock-Based Compensation

The Company accounts for employee stock-based compensation using the intrinsic value method prescribed by Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" and related interpretations. Reference is made to Note 9, "Benefit Plans" for a summary of the pro forma effect of SFAS No. 123, "Accounting for Stock Based Compensation," on the Company's results of operations for 2001, 2000 and 1999.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserve volumes and the related present value of estimated future net revenues to be received therefrom.

Net Income Per Common Share

Basic earnings per share ("EPS") is calculated by dividing net income attributable to common stock by the weighted average number of common shares outstanding during the period including the weighted average impact of the shares of common stock issued during the year from the date of issuance. Diluted EPS calculations also give effect to all dilutive potential common shares outstanding during the period.

The following is a reconciliation of the numerators and denominators used in the calculation of basic and diluted EPS for the years ended December 31, 2001, 2000 and 1999:

	2001			2000			1999		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
	(In thousands, except per share amounts)								
Basic EPS:									
Net Income Attributable to Common Stock and Share Amounts	$69,503	38,943	$1.78	$65,703	36,664	$1.79	$5,007	32,228	$.16
Dilutive Securities:									
Stock Options	—	1,284	—	—	473	—	—	238	—
Convertible preferred stock	—	—	—	875	760	—	—	—	—
Diluted EPS:									
Net Income Attributable to Common Stock and Assumed Share Amounts	$69,503	40,227	$1.73	$66,578	37,897	$1.76	$5,007	32,466	$.15

Options to purchase 1,180,000 and 1,447,000 shares of common stock in 2001 and 1999 were excluded in the computation of diluted earnings per share because the option exercise price was greater than the average market price of the Company's common stock. No options were excluded in 2000. Shares of common stock issuable upon conversion of preferred stock were excluded in the computation of diluted earnings per share in 1999 because their assumed conversion would be antidilutive.

Consolidated Statements of Cash Flows

The Company considers investments with an original maturity of three months or less when purchased to be cash equivalents. In July 1999, the Company issued 5.8 million shares of common stock valued at $63.5 million to Unocal Corporation as partial consideration for the acquisition of gas and oil assets (see Note 3). The Company received shares of stock valued at approximately $700,000 in June 1999 in settlement of an outstanding receivable from a working interest owner. In conjunction with the Stellarton acquisition in January 2001, the Company assumed long-term debt of $16.8 million (see Note 3).

Comprehensive Income

Comprehensive income represents all non-shareholder related changes in equity of an entity during the reporting period, including net income and charges directly to equity which are excluded from net income. The only reconciling items between net income as reflected in the statement of operations and comprehensive income for the years ended December 31, 2001, 2000 and 1999 were an unrealized (loss)/gain on marketable securities and a translation loss in 2001.

Exit Costs

In connection with the Company's decision in 1999 to relocate its corporate headquarters to Denver, Colorado, the Company recognized costs of $2.1 million as part of general and administrative expenses in 1999. Included in the costs were actual severance and transition payments made in 1999 and 2000 of $1.0 million and $.8 million, respectively. An additional accrual of $.3 million was made for future rental obligations for years 2000 through 2003.

(3) Acquisitions and Divestitures

Acquisition of Stellarton

On January 12, 2001, the Company completed an acquisition of 97.2% of the outstanding common shares of Stellarton. The remaining shares of Stellarton were then subsequently acquired pursuant to the compulsory acquisition provisions of the Business Corporation Act (Alberta). Including assumed debt of approximately $16.8 million, this business combination had a cash value of approximately $95 million and was accounted for as a purchase. The purchase price exceeded the fair value of the net assets of Stellarton by $20 million which was recorded as goodwill, and a portion of which was amortized in 2001 on a straight-line basis utilizing a twenty year life. Effective January 1, 2002 the Company adopted SFAS No. 142, "Goodwill and Other Intangible Assets" which eliminates the amortization of this goodwill in future periods. The net proved reserves associated with the Stellarton properties were estimated to be 75.8 billion cubic feet equivalent of gas (Bcfe) (unaudited) as of the closing date. The results of operations of Stellarton are included with the results of the Company from January 12, 2001 (closing date) forward.

The purchase price was allocated as follows (in thousands):

Cash paid for acquisition:	
Long-term debt incurred	$ 74,500
Long-term debt assumed	16,800
Direct acquisition costs	3,107
Total cash consideration	94,407
Allocation of acquisition costs:	
Oil and gas properties — proved	(117,000)
Unproved properties	(9,975)
Deferred income taxes	36,375
Gas sales contracts assumed	10,825
Net working capital deficit assumed	5,368
Goodwill	$ 20,000

In the acquisition costs identified above, the Company recorded a deferred income tax liability of $36.4 million to recognize the difference between the historical tax basis of the Stellarton assets and the acquisition costs recorded for book purposes. The recorded book value of the proved oil and gas properties and goodwill was increased to recognize this tax basis differential.

The gas sales contracts assumed in conjunction with the acquisition represented contractual obligations associated with the sale of natural gas at fixed prices below market conditions. These contracts were subsequently purchased (for an amount approximately equal to the original liability recorded) and cancelled in the quarter ended June 30, 2001.

Pro Forma Results of Operations (Unaudited)

The following table reflects the unaudited pro forma results of operations for the twelve months ended December 31, 2001 and 2000 as though the Stellarton Acquisition had occurred on January 1 of each period presented. The pro forma amounts are not necessarily representative of the results that may be reported in the future.

	Years Ended December 31,	
	2001	2000
	(In thousands, except per share data)	
Revenues	$328,267	$278,794
Net Income	69,503	64,008
Basic net income per share	1.78	1.75
Diluted net income per share	1.73	1.71

Acquisition of Certain Unocal Rocky Mountain Assets

In July 1999, the Company completed an acquisition of substantially all of the Rocky Mountain gas and oil assets of Unocal Corporation ("Unocal") for 5.8 million shares of common stock and $5 million in cash for a total purchase price of $68.5 million ($60.9 million after normal purchase adjustments) ("Unocal Acquisition"). The Unocal gas and oil assets are primarily located in the Paradox Basin of southwestern Colorado and southeastern Utah.

The purchase price was allocated as follows:

	(In millions)
Gas and oil properties	$37.5
Unproved properties	2.7
Gas processing plant	19.9
Oil pipeline	.8
	$60.9

Included in the acquisition is the Lisbon Plant, a modern sophisticated cyrogenic (60 million cubic feet per day capacity) natural gas processing plant that extracts natural gas liquids and merchantable helium, and separates carbon dioxide, hydrogen sulfide and nitrogen from the raw gas stream. The net proved reserves of these Unocal properties were estimated to be 93.2 Bcfe of gas as of the closing date of July 1, 1999. Approximately 65,000 net undeveloped acres were also acquired.

Pro Forma Information (Unaudited)

The following table presents the Unaudited pro forma revenues, net income and net income per share of the Company for the year ended December 31, 1999 assuming that the Unocal Acquisition occurred on January 1, 1999.

	Years Ended December 31, 1999 (In thousands, except for per share amounts)
Revenues	$226,141
Net income (loss)	$ 9,341
Net income (loss) attributable to common stock	$ 7,591
Net income (loss) per common share	
Basic	$ .22
Diluted	$ .21

Acquisition of Other Rocky Mountain Assets

In June 2000, the Company purchased an additional working interest in a field operated by the Company in the Wind River Basin in Wyoming. The acquired interests included an estimated 24.0 Bcfe of proved reserves purchased for total consideration of $15.2 million net of normal closing adjustments.

In September 1999, the Company purchased certain Rocky Mountain assets from an undisclosed seller for approximately $7.7 million in cash. Included in the acquisition was approximately 9.7 Bcfe of proved reserves and 34,000 net acres in the Greater Green River Basin of Wyoming.

Property Sales

During May 2001, the Company sold its interest in oil and gas properties primarily located in Oklahoma, with a net book value of $14.4 million, for net cash proceeds of $24.5 million. The resulting gain of $10.1 million is reflected in the Consolidated Statement of Operations.

In June and October 2001, the Company sold certain of the gathering and processing assets originally received in the Wildhorse distribution completed in 2000. The systems sold were considered non-strategic to the Company's operations and as these divestitures were part of the Wildhorse integration process, the net cash proceeds of $24.0 million were recorded as a reduction to the investment in gathering assets.

Proceeds derived from the 2001 property sales were utilized to repay bank indebtedness.

Sale of DJ Basin Properties

In June and October 1999, the Company sold its interest in the DJ Basin of Colorado for $2.3 million. The properties had a net book value of $1.1 million and, accordingly, a gain of $1.2 million was recorded on the sale. Proceeds from the sale of these properties were used to repay a portion of the Company's outstanding indebtedness under its credit facility existing at such time.

(4) Debt

In April 1998, the Company entered into a $75 million credit facility (the "Credit Facility") that had an original maturity of April 2001. In October 1998,the Company amended the Credit Facility by increasing the total borrowing amount to $100 million. The borrowing base was again increased in October 1999 as a result of the regular June 30 review which reflected the impact of the Unocal Acquisition. As of December 31, 1999, the outstanding balance was $81 million on the Credit Facility at an average interest rate of 6.9%.

On June 30, 2000, the Company entered into a new $125 million credit facility (the "New Credit Facility") that was to mature in June 2003. Under the terms of the New Credit Facility, the borrowing base was established at $225 million. At December 31, 2000, the outstanding balance on the New Credit Facility was $54 million at an average interest rate of 7.9%..

On March 20, 2001, as part of the final financing of the Stellarton acquisition, the Company repaid and cancelled its previous $125 million revolving credit facility and entered into a new $225 million credit facility (the "Global Credit Facility"). The Global Credit Facility is comprised of: a $75 million line of credit in the U.S. and a $55 million line of credit in Canada which both mature in March 2004, and a $95 million five-year term loan in Canada. The borrowing base under the Global Credit Facility was set at $300 million. The Global Credit Facility allows the lenders one scheduled redetermination of the borrowing base each December. In addition, the lenders may elect to require one unscheduled redetermination in the event the borrowing base utilization exceeds 50% of the borrowing base at any time for a period of 15 consecutive business days. At December 31, 2001, the Company had borrowings outstanding under the Global Credit Facility totaling $120.6 million or 40% of the borrowing base at an average interest rate of 4. 1%. The amount available for borrowing under the Global Credit Facility at December 31, 2001 was $104.4 million.

Borrowings under the Global Credit Facility are unsecured and bear interest, at the election of the Company, at a rate equal to (i) the greater of the global administrative agents prime rate or the federal funds effective rate plus an applicable margin, (ii) adjusted LIBOR for Eurodollar loans plus applicable margin, or (iii) Bankers' Acceptances plus applicable margin for Canadian dollar loans. Interest on amounts outstanding under the Global Credit Facility is due on the last day of each quarter for prime based loans, and in the case of Eurodollar loans with an interest period of more than three months, interest is due at the end of each three month interval.

The Global Credit Facility contains certain financial covenants and other restrictions similar to the limitations associated with the cancelled credit facility. The financial covenants of the Global Credit Facility require the Company to maintain a minimum consolidated tangible net worth of not less than $350 million (adjusted upward by 50% of quarterly net income and 50% of the net cash proceeds of any stock offering) and the Company will not permit its ratio of (i) indebtedness to (ii) earnings before interest expense, state and federal taxes and depreciation, depletion and amortization expense and exploration expense to be more than 3.0 to 1.0 as calculated at the end of each fiscal quarter.

(5) Taxes

The income tax (expense) benefit was different from amounts computed by applying the statutory federal and state income tax rates for the following reasons:

	2001	2000	1999
		(In thousands)	
Tax expense at 35% of income before income taxes and change in accounting principle	$(36,961)	$(37,225)	$(3,868)
State tax expense net of federal benefit	(2,112)	(2,127)	(221)
Canadian Crown payments (net of Alberta Royalty Tax Credit) not deductible for tax purposes	(4,136)	—	—
Canadian resource allowance	3,556	—	—
Canadian expenses deductible in the United States	1,845	—	—
Canadian Large Corporation Tax	(335)	—	—
Franchise and other taxes — United States	(486)	(1,614)	(682)
Adjustments to prior periods due to filed returns	502	—	—
Valuation allowance adjustment	—	1,953	622
Other	—	(767)	(144)
Total income tax expense	$(38,127)	$(39,780)	$(4,293)

Deferred income taxes result from recognizing income and expenses at different times for financial and tax reporting. In the United States, the largest differences are the tax effect of the capitalization of certain development, exploration and other costs under the successful efforts method of accounting. In Canada, differences result in part from accelerated cost recovery of oil and gas capital expenditures for tax purposes.

The components of the net deferred tax liability by geographical segment at December 31, 2001 and 2000 were as follows (all items were located within the United States as of December 31, 2000):

	December 31, 2001			December 31, 2000
	United States	Canada	Total	United States
		(In thousands)		
Deferred tax assets:				
Net operating loss carryforward	$ 6,918	$ 302	$ 7,220	$ 4,845
Percentage depletion carryforward	2,178	—	2,178	2,178
Alternative minimum tax credit carryforward	5,190	—	5,190	5,343
Other	300	—	300	36
Total gross deferred tax assets	14,586	302	14,888	12,402
Deferred tax liabilities:				
Property and equipment	(55,119)	(34,558)	(89,677)	(17,877)
Other	(405)	—	(405)	—
Total gross deferred tax liabilities	(55,524)	(34,558)	(90,082)	(17,877)
Net deferred tax liabilities	$(40,938)	$(34,256)	$(75,194)	$ (5,475)

The Alternative Minimum Tax (AMT) credit carryforward available to reduce future U.S. Federal regular taxes aggregated $5,190,000 at December 31, 2001. This amount may be carried forward indefinitely. U.S. Federal regular and AMT net operating loss carryforwards at December 31, 2001 were approximately $18,700,000 and $15,700,000, respectively, and will expire in 2019. AMT net operating loss carryforwards can be used to offset 90% of AMT income in future years. Realization of the benefit of these carryforwards is dependent upon the Company's ability to generate taxable earnings in future periods.

Percentage depletion carryforwards available to reduce future U.S. Federal taxable income aggregated $6,224,000 at December 31, 2001. This amount may be carried forward indefinitely.

Canadian net operating losses available to reduce future Canadian Federal income taxes were $700,000 ($1,084,000 CDN) at December 31, 2001 and will expire in 2006.

Canadian tax pools relating to the exploration, development and production of oil and natural gas which are available to reduce future Canadian Federal income taxes aggregated approximately $55,218,000 ($85,474,000 CDN) at December 31, 2001. These pool balances are deductible on a declining balance basis ranging from 10% to 100% of the balance annually. The amounts may be carried forward indefinitely.

In conjunction with the acquisition of Stellarton in January 2001, the purchase price allocation resulted in a difference between the book and tax basis of approximately U.S. $63 million. Based upon Stellarton's historical tax rate of 43%, a deferred tax liability of approximately $36.4 million was recognized.

(6) Advances from Gas Purchasers

In 1998, the Company received $24.5 million from purchasers as advance payments for future natural gas deliveries of 35,000 Mmbtu per day for a twelve month period commencing January 1999. In connection with the advances, the Company entered into gas price swap contracts with third parties under which the Company became a fixed price payor for identical volumes at a weighted average price of $2.02 per MMBtu. The net result of these transactions is that gas delivered to the purchaser is reported as revenue at a rate that approximates the prevailing spot price.

The advance payments were classified as advances on the balance sheet and were reduced as gas was delivered to the purchasers under the terms of the contracts. Gas volumes delivered to the purchaser were reported as revenue at prices used to calculate the amount advanced, before imputed interest, minus or plus amounts paid or received by the Company applicable to the price swap agreements. Interest expense was recorded based on an average rate of 9.7% on the advances.

(7) Trading Activities

The Company engages in natural gas trading activities which involve purchasing natural gas from third parties and selling natural gas to other parties. These transactions are typically short-term in nature and involve positions whereby the underlying quantities generally offset. The Company also markets a significant portion of its own production. Marketing and trading income associated with these activities is presented on a net basis in the financial statements. The Company's gross trading activities are summarized below.

	Years Ended December 31,		
	2001	2000	1999
		(In thousands)	
Revenues	$123,767	$111,756	$68,013
Operating expenses	122,776	108,370	68,524
Net trading margin	$ 991	$ 3,386	$ (511)

(8) **Stockholders' Equity**

Common Stock

The Company's Common Stock is $.10 par value per share. There were 55,000,000 authorized shares of Common Stock at December 31, 2001, of which 39,127,649 shares and 38,351,860 shares were outstanding at December 31, 2001 and 2000, respectively.

In July 1999, the Company issued 5.8 million shares of common stock to Unocal as partial consideration in connection with the Unocal Acquisition (see Note 3).

Rights Plan

On March 1, 1991, the Board of Directors adopted a Rights Plan designed to help assure that all stockholders receive fair and equal treatment in the event of a hostile attempt to take over the Company, and to help guard against abusive takeover tactics. The Board of Directors declared a dividend of one preferred share purchase right (a "Right") for each outstanding share of Common Stock. The dividend was distributed on March 15, 1991 to the stockholders of record on that date. As of March 1, 2001, the Board of Directors amended and restated the Rights Plan. Each Right entitles the registered holder to purchase, for the $120 per share exercise price, shares of Common Stock or other securities of the Company (or, under certain circumstances, of the acquiring person) worth twice the per share exercise price of the Right.

The Rights will be exercisable only if a person or group acquires 15% or more of the Company's Common Stock or announces a tender offer which would result in ownership by a person or group of 15% or more of the Common Stock. The date on which the above occurs is to be known as the "Distribution Date". The Rights will expire on March 1, 2011, unless extended or redeemed earlier by the Company.

At the time the Rights dividend was declared, the Board of Directors further authorized the issuance of one Right with respect to each share of the Company's Common Stock that shall become outstanding between March 15, 1991 and the earlier of the Distribution Date or the expiration or redemption of the Rights. Until the Distribution Date occurs, the certificates representing shares of the Company's Common Stock also evidence the Rights. Following the Distribution Date, the Rights will be evidenced by separate certificates.

The provisions described above may tend to deter any potential unsolicited tender offers or other efforts to obtain control of the Company that are not approved by the Board of Directors and thereby deprive the stockholders of opportunities to sell shares of the Company's Common Stock at prices higher than the prevailing market price. On the other hand, these provisions will tend to assure continuity of management and corporate policies and to induce any person seeking control of the Company or a business combination with the Company to negotiate on terms acceptable to the then elected Board of Directors.

Preferred Stock

In January 1996, in connection with the KNPC Acquisition the Company issued 1,000,000 shares of its $1.75 Convertible Preferred Stock, Series A (the "Preferred Stock") to the seller. There are 2,500,000 shares of Preferred Stock authorized. The holder of the Preferred Stock was entitled to receive cumulative dividends at the annual rate of $1.75 per share, payable in cash quarterly on the fifteenth day of March, June, September and December in each year.

The Preferred Stock was exchangeable, in whole or in part, at the option of the Company on any dividend payment date at any time on or after March 15, 1999, and prior to March 15, 2001, for shares of Common Stock at the exchange rate of 1.666 shares of Common Stock for each share of Preferred Stock; provided that (i) on or prior to the date of exchange, the Company shall have declared and paid or set apart for payment to the holders of Preferred Stock all accumulated and unpaid dividends to the date of exchange, and (ii) the current market price of the Common Stock is above $18.375 (the "Threshold Price").

On June 15, 2000, the Company elected to exchange 1,666,000 shares of its Common Stock for all 1,000,000 outstanding shares of the Preferred Stock as the Common Stock had traded above the Threshold Price. Dividends on the Preferred Stock were paid through June 14, 2000 and did not accrue after the June 15, 2000 exchange date. The Preferred Stock is no longer outstanding.

(9) Benefit Plans

1989 Plan

The Company's 1989 Stock Option Plan expired in December 1999. Options to purchase 163,000 shares of the Company's Common Stock, which would have expired in December 1999, were exercised in 1999 at an average price of $4.76. As of December 31, 2001, options to purchase 390,700 shares of the Company's common stock were outstanding under the 1989 Plan. These options will expire between 2003 and 2009 if not previously exercised.

1993 Plan

In February 1993, the Board of Directors adopted the Company's 1993 Stock Option Plan (the "1993 Plan"). The 1993 Plan provides for issuance of options to certain employees and directors to purchase shares of Common Stock. In November 1999, the aggregate number of shares of Common Stock that may be issued under the 1993 Plan was increased from 2,700,000 shares to 3,200,000 shares. The aggregate number of shares was subsequently increased to 4,100,000 in January 2001. The exercise price, vesting and duration of the options may vary and will be determined at the time of issuance. Options to purchase 2,767,700 shares of the Company's Common Stock were outstanding under this plan as of December 31, 2001.

1999 Plan

The 1999 Long Term Incentive Plan (the "1999 Plan") was adopted by the Board of Directors on February 17, 1999, and approved by the stockholders on May 20, 1999. The 1999 Plan provides for the grant of stock options, restricted stock awards, performance awards and incentive awards. There were no grants made in 1999 under the 1999 Plan and options to purchase 378,700 and 490,000 shares of the Company's Common Stock were granted in 2001 and 2000, respectively. The aggregate number of shares of common stock, which may be issued under the 1999 Plan, may not exceed 2,000,000 shares. The maximum value of any performance award granted to any one individual during any calendar year may not exceed $500,000. The exercise price, vesting and duration of any grants may vary and will be determined at the time of issuance. Options to purchase 760,600 shares of the Company's Common Stock were outstanding under this plan as of December 31, 2001.

A summary of the status of the plans described above, as of the dates indicated, and the changes during the years then ended, is presented in the table and narrative below:

	Years Ended December 31,					
	2001		2000		1999	
	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price
	(Shares in thousands)					
Outstanding, beginning of year	3,412	$14.52	4,139	$13.77	3,402	$13.22
Granted	1,531	29.56	852	15.14	1,178	13.91
Exercised	(778)	14.50	(1,378)	12.67	(248)	6.98
Cancellations	(246)	26.45	(201)	14.77	(193)	13.56
Outstanding, end of year	3,919	19.60	3,412	14.52	4,139	13.77
Exercisable, end of year	1,331	14.24	1,659	14.22	2,226	13.10
Available for grant, end of year	1,305		1,722		2,392	

The weighted average fair value of options granted during the years ended December 31, 2001, 2000, and 1999 was $18.12, $9.78, and $9.72, respectively.

The following table summarizes information about stock options outstanding at December 31, 2001:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Shares Under Outstanding Options	Weighted Average Life (Years)	Weighted Average Exercise Price	Number of Shares Under Exercisable Options	Weighted Average Exercise Price
	(Shares in thousands)				
$ 3.81 to 11.88	140	2.50	$ 7.89	135	$ 7.85
$11.94 to 13.50	1,000	6.31	12.92	322	12.84
$13.63 to 15.69	1,112	5.98	15.14	787	15.25
$16.06 to 23.75	469	8.77	20.91	82	19.70
$23.89 to 30.13	321	9.32	27.47	5	26.46
$31.00 to 34.19	877	9.13	31.15	—	34.00
	3,919	7.25	19.60	1,331	14.24

In January 2001 the Company's Chairman and Chief Executive Officer resigned to become the United States Secretary of Commerce. The Company accelerated the vesting of 228,300 of his outstanding stock options upon his resignation and as a result of this modification to the initial terms of these stock options, a new measurement date was established. Based upon the difference between the market price of the Company's stock on the date the stock options were amended and the exercise price of the stock options, a non-cash pre-tax charge to earnings of $3.8 million was recognized.

The Company accounts for its stock-based compensation using the intrinsic value method prescribed by APB Opinion No. 25 and related interpretations, under which no compensation cost has been recognized for grants of options under the stock option plans. Alternatively, if compensation costs for these plans had been determined in accordance with SFAS No. 123, the Company's net income and net income per common share would approximate the following pro forma amounts:

	Years Ended December 31,		
	2001	2000	1999
	(In thousands, except per share amounts)		
Net Income			
As Reported	$69,503	$65,703	$5,007
Pro Forma	$66,570	$63,693	$ 451
Basic Net Income per Common Share:			
As Reported	$ 1.78	$ 1.79	$ .16
Pro Forma	$ 1.71	$ 1.74	$ .01
Diluted Net Income per Common Share:			
As Reported	$ 1.73	$ 1.76	$ .15
Pro Forma	$ 1.65	$ 1.70	$ .01

The fair value of each option is estimated as of the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions used for grants in 2001, 2000, and 1999, respectively: (i) risk-free interest rates of 4.46, 6.25, and 6.20 percent; (ii) expected lives of 7.0, 7.0 and 7.0 years, (iii) expected volatility of 56.0, 53.7, and 47.6 percent, and (iv) no dividend yields.

Profit Sharing, ESOP and KSOP Plans

Effective April 1, 1985, the Company adopted a profit sharing plan (the "Profit Sharing Plan") for the benefit of all employees. Under the Profit Sharing Plan, the Company could contribute to a trust either stock or cash in such amounts as the Company deemed advisable.

Effective April 1, 1986, the Company adopted an employee stock ownership plan (the "ESOP") for the benefit of all employees. Under the ESOP, the Company could contribute cash or the Company's Common Stock to a trust in such amounts as the Company deemed advisable.

Effective April 1, 1990, the Profit Sharing Plan was amended to provide for voluntary employee contributions under Section 401(k) of the Internal Revenue Code of 1986, as amended. The Profit Sharing Plan was further amended to provide employees with the ability to give direct investment instructions to the Profit Sharing Trustee for amounts held for their benefit.

Effective January 1, 1996 the Company adopted the KSOP which is a merger of the ESOP and the Profit Sharing Plan which contains 401(k) profit sharing plan and employer stock ownership plan provisions for the benefit of those persons who qualify as participants. Effective January 1, 2000, the Company adopted a 401(k) retirement plan that superseded the KSOP plan. On December 1, 2001, the Company amended and restated its 401(k) retirement plan. The Company has, at its discretion, a policy to match employee contributions to the plan. As of December 31, 2001, the Company's policy was to match 100% of the employee contribution up to a total match of seven percent of the employee's salary. The match for the years ended December 31, 2001, 2000 and 1999, was approximately $864,000, $492,000 and $422,000, respectively.

(10) Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of financial instruments. The carrying values of trade receivables and trade payables approximated market value. The carrying amounts of cash and cash equivalents approximated fair value due to the short maturity of these instruments. The carrying value of debt approximated fair value because the interest rate is variable and is reflective of current market conditions.

Commodity Price Swaps

As discussed in Note 6, as of December 31, 1998, in connection with advance payments for future natural gas deliveries, the Company had three gas price swap contracts outstanding whereby the Company became a fixed price payor for a total of 35,000 Mmbtu per day at a weighted average price of $2.02. The swap contracts were completely settled as of December 31, 1999.

Derivative Instruments and Hedging Activities

The Company has entered into natural gas and crude oil futures contracts with counter parties to hedge the price risk associated with a portion of its production. These derivatives are not held for trading purposes. To the extent that changes occur in the market prices of natural gas and oil, the Company is exposed to market risk on these open contracts. This market risk exposure is generally offset by the gain or loss recognized upon the ultimate sale of the commodity hedged.

In December 2000, the Company entered into several costless collar arrangements (put and call options) to hedge approximately 40% of the Company's expected 2001 U.S. gas production. These positions were open as of January 1, 2001 when the Company adopted SFAS 133 and SFAS 138. Based upon the natural gas index pricing strip in effect as of January 1, 2001, the impact of these hedges at adoption resulted in a charge to Other Comprehensive Loss of $4.5 million (net of the deferred tax benefit of $2.6 million) and the recognition of a derivative liability of $7.1 million. As of December 31, 2001, the Company had no outstanding cash flow hedges. The Company received cash settlements of $15.4 million in 2001, which were recognized as increases in gas and oil sales.

The Company also entered into natural gas basis swaps covering essentially the same time period of the natural gas costless collars. These transactions were executed in December, 2000 with settlement periods in 2001. Under SFAS 133, these basis swaps did not qualify for hedge accounting. Accordingly, upon adoption of SFAS 133, these basis swaps resulted in the recognition of derivative gains of $2.0 million, recorded as a cumulative effect of a change in accounting principle, (net of the deferred tax liability of $1.2 million) and a derivative asset of $3.2 million. A $.9 million gain was recognized in conjunction with the change in the value of these contracts in the year ended December 31, 2001. Cash receipts of $4.1 million were received during this period. No basis swaps were outstanding at December 31, 2001.

In August 2001, the Company entered into NYMEX based swaps for the September and October 2001 contract periods. Basis swaps were purchased on these quantities to correlate the volumes back to markets where the Company actually delivers gas. Cash settlements of $2.0 million were received on these contracts which increased gas and oil sales.

In October 2001, the Company entered into NYMEX based swaps for the November 2001 contract period. Basis swaps were purchased on these quantities to correlate the volumes back to markets where the Company actually delivers gas. A cash settlement of $1.5 million was paid on the contracts which decreased gas and oil sales.

As of December 31, 2001, the Company had no open derivative contracts.

(11) Related Parties and Significant Customers

Related Parties

Certain of the Company's directors participate (either individually or indirectly through various entities) with the Company and other unrelated investors in the drilling, development and operation of gas and oil properties. Related party transactions are non-interest bearing and are settled in the normal course of business with terms which, in management's opinion, are similar to those with other joint owners.

The Company has engaged a law firm that previously employed one of the Company's directors as a partner. The amounts paid to this firm for the years ended December 31, 2001, 2000 and 1999, were approximately $173,000, $162,000 and $97,000, respectively. The Company also paid approximately $41,000, $44,000 and $38,000 during the years ended December 31, 2001, 2000 and 1999, respectively, to a consulting firm that has a partner who serves as a director of the Company.

The Company participates in exploration activity with a partnership, one of whose partner is a director of the Company. During the years ended December 31, 2001, 2000, and 1999, the Company billed $621,000, $612,000 and $579,000, respectively, to such partnership for their share of certain leasehold and drilling costs.

In addition, a director of the Company is also a director of a drilling contractor that has performed drilling services on wells operated by the Company. The fees charged for these services were $787,000 and $1,860,000 for the years ended December 31, 2000 and 1999, respectively. No fees were paid in 2001.

In management's opinion, the above described transactions and services were provided on the same terms as could be obtained from non-related sources.

Significant Customers

Gas and oil sales to Conoco, Inc. accounted for 11%, 11% and 12% of gas and oil sales for the years ended December 31, 2001, 2000 and 1999, respectively. Because there are numerous other parties available to purchase the Company's production, the Company believes the loss of this purchaser would not materially affect its ability to sell natural gas or crude oil.

Concentration of Credit Risk

The Company's revenues are derived principally from uncollateralized sales to customers in the gas and oil industry. The concentration of credit risk in a single industry affects the Company's overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions. The Company has not experienced significant credit losses on such receivables.

(12) Segment Information

The Company operates in four reportable segments: (i) gas and oil exploration and development for the United States and Canada, (ii) marketing, gathering and processing and (iii) drilling. The long-term financial performance of each of the reportable segments is affected by similar economic conditions.

The Company's gas and oil exploration and development segment operates primarily in the Wind River and Green River Basins of Wyoming, the Piceance Basin of Colorado, the Paradox Basin of Utah and Colorado, the Val Verde of west Texas, the Permian Basin of west Texas and southwestern New Mexico, east Texas and the western sedimentary basin of Canada. The marketing, gathering and processing activities of the Company are conducted through Retex, Wildhorse and TBIFS, primarily in the Rocky Mountain region. The drilling segment operates under the name of Sauer Drilling Company and serves the drilling needs of operators in the central Rocky Mountain region in addition to drilling for the Company.

The accounting policies of the segments are the same as those described in Note 2 of the Notes to Consolidated Financial Statements. The Company evaluates performance based on profit or loss from operations before income taxes, accounting changes, nonrecurring items and interest income and expense.

The Company accounts for intersegment sales transfers as if the sales or transfers were to third parties, that is, at current prices.

The following tables present information related to the Company's reportable segments (in thousands):

	As of or Year Ended December 31, 2001				
	Gas and Oil Exploration and Development (United States)	Gas and Oil Exploration and Development (Canada)	Marketing, Gathering and Processing	Drilling	Total Segments
Revenues from external purchasers	$162,158	$ 30,133	$266,386	$14,828	$473,505
Intersegment revenues	83,991	—	6,556	12,777	103,324
Depreciation, depletion and amortization	55,692	14,079	2,951	1,649	74,371
Segment profit	85,932	5,593	9,671	5,141	106,337
Assets	644,483	165,399	59,333	19,606	888,821
Capital and exploration expenditures	316,934	31,280	9,300	5,237	362,751

	As of or Year Ended December 31, 2000			
	Gas and Oil Exploration and Development (United States)	Marketing, Gathering and Processing	Drilling	Total Segments
Revenues from external purchasers	$153,026	$229,100	$11,472	$393,598
Intersegment revenues	55,150	—	6,309	61,459
Depreciation, depletion and amortization	46,853	2,959	1,707	51,519
Segment profit	99,243	12,165	1,635	113,043
Assets	545,639	110,438	13,612	669,689
Capital and exploration expenditures	132,117	16,347	2,725	151,189

	As of or Year Ended December 31, 1999			
	Gas and Oil Exploration and Development (United States)	Marketing, Gathering and Processing	Drilling	Total Segments
Revenues from external purchasers	$ 85,138	$116,687	$5,643	$207,468
Intersegment revenues	21,365	—	4,348	25,713
Depreciation, depletion and amortization	40,532	3,107	1,324	44,963
Segment profit	15,976	1,026	149	17,151
Assets	467,561	90,262	9,333	567,156
Capital and exploration expenditures	120,146	4,080	1,416	125,642

The following tables reconcile segment information to consolidated totals:

	As of or Years Ended December 31,		
	2001	2000	1999
		(In thousands)	
Revenues			
Revenue from external purchasers	$473,505	$393,598	$207,468
Marketing and trading expenses offset against related revenues for net presentation	(170,774)	(148,480)	(91,439)
Gain on sale of property	10,078	—	1,265
Intersegment revenues	103,324	61,459	25,713
Intercompany eliminations	(89,809)	(52,667)	(19,596)
Total consolidated revenues	$326,324	$253,910	$123,411
Profit			
Total reportable segment profit/loss	$106,337	$113,043	$ 17,151
Interest and other	(6,139)	(5,967)	(6,825)
Gain on sale of property	10,078	—	1,265
Eliminations and other	(4,672)	(718)	(541)
Income before income taxes	$105,604	$106,358	$ 11,050
Depreciation, depletion and amortization			
Total reportable segment depreciation, depletion and amortization	$ 74,371	$ 51,519	$ 44,963
Elimination and other	—	(1,102)	(748)
	$ 74,371	$ 50,417	$ 44,215
Assets			
Total reportable segment assets	$888,821	$669,689	$567,156
Elimination and other	(43,846)	(40,154)	(30,857)
	$844,975	$629,535	$536,299

(13) Commitments and Contingencies

The Company's operations are subject to numerous governmental regulations that may give rise to claims against the Company. In addition, the Company is a defendant in various lawsuits generally incidental to its business. The Company does not believe that the ultimate resolution of such litigation will have a material adverse effect on the Company's financial position, results of operations or cash flows.

Lease Commitments

At December 31, 2001, the Company had long-term leases through 2004 covering certain of its facilities and equipment. The minimum rental commitments under non-cancelable operating leases with lease terms in excess of one year are as follows:

Years Ending December 31,	Commitment Amount
	(In thousands)
2002	$1,502
2003	1,353
2004	191
	$3,046

Total rental expense incurred for the years ended December 31, 2001, 2000 and 1999, was approximately $1,558,000, $1,447,000, and $1,139,000, respectively, all of which represented minimum rentals under non-cancelable operating leases.

Firm Transportation Commitments

On September 1, 1999, the Company took assignment of firm transportation commitments within Wildhorse based upon its 45% interest in Wildhorse.

Based upon current rates, the Company's obligation for such firm transportation on that pipeline and others for the next five years and thereafter is as follows:

Years Ending December 31,	Commitment Amount
	(In thousands)
2002	$ 5,176
2003	4,088
2004	2,618
2005	1,852
2006	573
Thereafter	596
	$14,903

Processing Commitment

In March 2001, the Company entered into a new gas processing agreement with a third party to expand available capacity for its gas production from the White River Dome coal bed methane project in the Piceance Basin. The plant commenced operations in October 2001. As processing fees, the Company is obligated to reimburse the third party for certain variable expenses of the plant associated with the processed volumes and compression made available during the ten-year term of this agreement. Additionally, the Company pays the third party $189,000/month to cover the plants fixed operating costs and capital recovery over the term of this agreement.

Drilling Obligation

To assure the availability of a drilling rig in conjunction with the continuing exploration program at the Deep Valley prospect in West Texas, the Company entered into a two-year commitment with a drilling contractor in 2001. The rig became available on March 1, 2002 after which a 90-day period is allowed under the terms of the agreement to mobilize the rig and commence the two-year drilling obligation. Under the terms of this arrangement, the Company is required to pay a daywork rate of $20,100/day during drilling operations, $16,700/day for rig moves and a special standby fee of $6,000/day during the initial 90-day commencement period.

Environmental Matters

Rocno Corporation, a wholly-owned subsidiary of the Company, is a party to a trust agreement in connection with the environmental clean-up plan for the Sheridan Superfund Site in Waller County, Texas. Rocno's share of the estimated cleanup costs was accrued in the consolidated financial statements at December 31, 2001. Based on the amount of remediation costs estimated for this site and the Company's de minimis contribution, if any, the Company believes that the outcome of this proceeding will not have a material adverse effect on its financial position or results of operations.

(14) Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(In thousands, except per share amounts)				
Year ended December 31, 2001					
Revenues	$118,684	$95,386	$59,252	$53,002	$326,324
Gross profit(1)	90,609	62,460	45,155	37,008	235,232
Net income attributable to common stock	37,466	26,234	5,770	33	69,503
Net income per common share(2)					
Basic	.97	.67	.15	—	1.78
Diluted	.93	.65	.14	—	1.73
Year ended December 31, 2000					
Revenues	$ 45,681	$53,388	$65,400	$89,441	$253,910
Gross profit(1)	29,952	39,506	48,185	68,644	186,287
Net income attributable to common stock	7,271	12,165	17,103	29,164	65,703
Net income per common share(2)					
Basic	.21	.34	.46	.77	1.79
Diluted	.20	.33	.44	.73	1.76

(1) Gross Profit is computed as the excess of gas and oil sales and marketing, trading gathering and processing revenues over operating expenses. Operating expenses are those associated directly with gas and oil sales and marketing, gathering and processing revenues and include lease operations, gas and oil related taxes and cost of gas sold.

(2) The sum of the individual quarterly net income per share does not agree with year-to-date net income per share as each period's computation is based on the weighted average number of common shares outstanding during that period.

(15) Supplemental Information Related to Gas and Oil Activities

The following tables set forth certain historical costs and operating information related to the Company's gas and oil producing activities:

Capitalized Costs and Costs Incurred

	December 31,		
	2001	2000	1999
		(In thousands)	
Capitalized costs			
Proved gas and oil properties	$ 780,300	$ 526,269	$ 427,676
Unproved gas and oil properties	69,328	49,722	42,785
Total gas and oil properties	849,628	575,991	470,461
Less: Accumulated depreciation, depletion and amortization	(213,297)	(160,738)	(116,403)
Net capitalized costs	$ 636,331	$ 415,253	$ 354,058

	United States	Canada	Total
		(In thousands)	
2001			
Costs incurred			
Proved property acquisition costs	$ 3,649	$ 85,025	$ 88,674
Unproved property acquisition costs	16,496	14,132	30,628
Exploration costs	55,357	2,585	57,942
Development costs	138,815	24,395	163,210
Total	$214,317	$126,137	$340,454
2000			
Costs incurred			
Proved property acquisition costs	$ 17,111	$ —	$ 17,111
Unproved property acquisition costs	16,831	—	16,831
Exploration costs	18,362	—	18,362
Development costs	74,406	—	74,406
Total	$126,710	$ —	$126,710
1999			
Costs incurred			
Proved property acquisition costs(1)	$ 65,753	—	$ 65,753
Unproved property acquisition costs	6,945	—	6,945
Exploration costs	12,016	—	12,016
Development costs	33,232	—	33,232
Total	$117,946	$ —	$117,946

(1) For 1999 proved property acquisition costs includes $19.9 million for a gas processing plant acquired in connection with the Unocal Acquisition (see Note 3).

Gas and Oil Reserve Information (Unaudited)

The following summarizes the policies used by the Company in preparing the accompanying gas and oil reserve disclosures, Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Gas and Oil Reserves and reconciliation of such standardized measure between years.

Estimates of proved and proved developed reserves at December 31, 1999, were principally prepared by independent petroleum consultants. The reserve estimates for the years ended December 31, 2001 and 2000 were prepared by the Company's petroleum engineering staff and audited by the independent petroleum consultants. Proved reserves are estimated quantities of natural gas and crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be recovered through existing wells with existing equipment and operating methods. The Company's gas and oil reserves are located in the United States and Canada.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year end economic conditions.

2. The estimated future cash flows from proved reserves were determined based on year-end prices, except in those instances where fixed and determinable price escalations are included in existing contracts.

3. The future cash flows are reduced by estimated production costs and costs to develop and produce the proved reserves, all based on year end economic conditions and by the estimated effect of future income taxes based on the then-enacted tax law, the Company's tax basis in its proved gas and oil properties and the effect of net operating loss, investment tax credit and other carryforwards.

The standardized measure of discounted future net cash flows does not purport to present, nor should it be interpreted to present, the fair value of the Company's gas and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

Quantities of Gas and Oil Reserves (Unaudited)

The following table presents estimates of the Company's net proved and proved developed natural gas and oil reserves (including natural gas liquids).

	Reserve Quantities					
	Gas (Mmcf)			Oil(1) (Mbls)		
	United States	Canada	Total	United States	Canada	Total
Proved reserves:						
Estimated reserves at December 31, 1998	372,022	—	372,022	5,682	—	5,682
Revisions of previous estimates	(8,571)	—	(8,571)	1,505	—	1,505
Purchases of minerals in place	65,982	—	65,982	6,989	—	6,989
Extensions and discoveries	58,032	—	58,032	292	—	292
Sales of minerals in place	(1,018)	—	(1,018)	(22)	—	(22)
Production	(40,514)	—	(40,514)	(1,445)	—	(1,445)
Estimated reserves at December 31, 1999	445,933	—	445,933	13,001	—	13,001
Revisions of previous estimates	50,852	—	50,852	(311)	—	(311)
Purchases of minerals in place	28,960	—	28,960	17	—	17
Extensions and discoveries	60,827	—	60,827	470	—	470
Sales of minerals in place	—	—	—	(137)	—	(137)
Production	(51,199)	—	(51,199)	(1,847)	—	(1,847)
Estimated reserves at December 31, 2000	535,373	—	535,373	11,193	—	11,193
Revisions of previous estimates	(47,647)	(7,058)	(54,705)	(49)	(112)	(161)
Purchases of minerals in place	3,000	58,809	61,809	—	2,838	2,838
Extensions and discoveries	164,561	14,920	179,481	2,937	648	3,585
Sales of minerals in place	(16,072)	(483)	(16,555)	(181)	(169)	(350)
Production	(57,163)	(6,661)	(63,824)	(1,797)	(301)	(2,098)
Estimated reserves at December 31, 2001	582,052	59,527	641,579	12,103	2,904	15,007
Proved developed reserves:						
December 31, 1998	263,747	—	263,747	4,029	—	4,029
December 31, 1999	333,858	—	337,858	11,398	—	11,398
December 31, 2000	431,824	—	431,824	10,089	—	10,089
December 31, 2001	428,719	51,392	480,111	9,628	2,339	11,967

(1) Oil volumes include natural gas liquids which were insignificant until 1999. For 1999, purchases of minerals in place and production include 6.0 million and 0.5 million barrels, respectively, of natural gas liquids. Proved developed reserves at December 31, 1999 include 6.0 million barrels of natural gas liquids related to the 1999 Unocal Acquisition. In 2000, liquids production was 1.1 million barrels with 5.1 million barrels of proved developed reserves of natural gas liquids remaining at December 31, 2000. For 2001, liquids production was 1.1 million barrels in the United States and .1 million barrels in Canada. At December 31, 2001 proved developed reserves included 7.0 million barrels of natural gas liquids of which 1.4 million barrels were associated with the Canadian properties.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Gas and Oil Reserves (Unaudited)

	December 31, 2001			December 31, 2000	December 31, 1999
	United States	Canada	Total	United States	United States
			(In thousands)		
Future cash flows	$1,448,747	$188,317	$1,637,064	$5,028,357	$1,107,515
Future production costs	(530,791)	(57,248)	(588,039)	(857,767)	(320,397)
Future development costs	(164,226)	(5,525)	(169,751)	(89,216)	(85,712)
Future net cash flows before tax	753,730	125,544	879,274	4,081,374	701,406
Future income taxes	(89,389)	(30,538)	(119,927)	(1,409,295)	(119,950)
Future net cash flows after tax	664,341	95,006	759,347	2,672,079	581,456
Annual discount at 10%	(275,838)	(30,813)	(306,651)	(1,196,324)	(247,897)
Standardized measure of discounted future net cash flows	$ 388,503	$ 64,193	$ 452,696	$1,475,755	$ 333,559
Discounted future net cash flows before income taxes	$ 429,906	$ 71,382	$ 501,288	$2,187,925	$ 393,423

Changes in Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

	Year Ended December 31, 2001		
	United States	Canada	Total
		(In thousands)	
Gas and oil sales, net of production costs(1)	$ (180,218)	$(24,926)	$ (205,144)
Net changes in anticipated prices and production cost	(1,821,163)	(66,916)	(1,888,079)
Extensions and discoveries, less related costs	92,376	20,262	112,638
Changes in estimated future development costs	(868)	—	(868)
Previously estimated development costs incurred	36,691	7,693	44,384
Net change in income taxes	670,767	(7,188)	663,579
Purchase of minerals in place	3,500	153,017	156,517
Sales of minerals in place	(61,623)	(1,155)	(62,778)
Accretion of discount	218,793	—	218,793
Revision of quantity estimates	(34,549)	(12,706)	(47,255)
Changes in production rates and other	(10,957)	(3,889)	(14,846)
Change in Standardized Measure	$(1,087,251)	$ 64,192	$(1,023,059)

(1) Net of hedging revenue of $15.8 million on United States production.

	Year Ended December 31, 2000			Year Ended December 31, 1999		
	United States	Canada	Total	United States	Canada	Total
			(In thousands)			
Gas and oil sales, net of production costs	$ (169,375)	$ —	$ (169,375)	$(76,052)	$ —	$(76,052)
Net changes in anticipated prices and production cost	1,535,058	—	1,535,058	32,745	—	32,745
Extensions and discoveries, less related costs	251,410	—	251,410	31,796	—	31,796
Changes in estimated future development costs	8,831	—	8,831	21,246	—	21,246
Previously estimated development costs incurred	26,084	—	26,084	1,435	—	1,435
Net change in income taxes	(652,306)	—	(652,306)	(27,561)	—	(27,561)
Purchase of minerals in place	18,917	—	18,917	98,419	—	98,419
Sales of minerals in place	(679)	—	(679)	(1,207)	—	(1,207)
Accretion of discount	39,343	—	39,343	25,402	—	25,402
Revision of quantity estimates	198,625	—	198,625	369	—	369
Changes in production rates and other	(113,712)	—	(113,712)	5,250	—	5,250
Change in Standardized Measure	$1,142,196	$ —	$1,142,196	$111,842	$ —	$111,842

ITEM 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

PART III

ITEM 10. *Directors and Executive Officers of the Registrant*

Certain information regarding Directors of the Company will be included in the Company's definitive proxy statement to be filed with the Securities and Exchange Commission not later than 120 days after the end of the Company's fiscal year covered by this Form 10-K and such information is incorporated by reference to the Company's definitive proxy statement. Information concerning the Executive Officers of the Company appears under Item I of this Annual Report on Form 10-K.

ITEM 11. *Executive Compensation*

Certain information regarding compensation of executive officers of the Company will be included in the Company's definitive proxy statement to be filed with the Securities and Exchange Commission not later than 120 days after the end of the Company's fiscal year covered by this Form 10-K and such information is incorporated by reference to the Company's definitive proxy statement.

ITEM 12. *Security Ownership of Certain Beneficial Owners and Management*

Certain information regarding security ownership of certain beneficial owners and management will be included in the Company's definitive proxy statement to be filed with the Securities and Exchange Commission not later than 120 days after the end of the Company's fiscal year covered by this Form 10-K and such information is incorporated by reference to the Company's definitive proxy statement.

ITEM 13. *Certain Relationships and Related Transactions*

Certain information regarding transactions with management and other related parties will be included in the Company's definitive proxy statement to be filed with the Securities and Exchange Commission not later than 120 days after the end of the Company's fiscal year covered by this Form 10-K and such information is incorporated by reference to the Company's definitive proxy statement.

PART IV

ITEM 14. ***Exhibits, Consolidated Financial Statement Schedules and Reports on Form 8-K***

(1) See Index to Consolidated Financial Statements under Item 8 of this Annual Report on Form 10-K.

(2) None

(3) Exhibits:

2.1	— Purchase and Sale Agreement, dated June 8, 1999, between Union Oil Company of California and the Registrant. (Incorporated by reference to Exhibit 10.1 in the Registrant's Form 8-K Report dated July 19, 1999 and filed with the Securities and Exchange Commission on July 19, 1999)
2.2	— Pre-Acquisition Agreement, dated December 13, 2000, between Stellarton Energy Corporation and the Registrant. (Incorporated by reference to Exhibit 2.2 in the Registrant's Form 10-K Report for the fiscal year ended December 31, 2000, and filed with the Securities and Exchange Commission on March 13, 2001)
3.1	— Certificate of Incorporation, as amended, of the Registrant. (Incorporated by reference to Exhibit 3.1 in the Registrant's Form S-8 Report filed with the Securities and Exchange Commission on December 6, 2000)
3.2	— Amended and Restated Bylaws, dated May 10, 2001. (Incorporated by reference to Exhibit 3.1 in the Registrant's Form 10-Q, for the quarterly period ended March 31, 2001, and filed with the Securities and Exchange Commission on May 14, 2001)
4.1	— First Amended and Restated Rights Agreement dated March 1, 2001 between the Registrant and EquiServe Trust Company, N.A. (Incorporated by reference to Exhibit 4.2 in the Registrant's Form 10-K Report for the fiscal year ended December 31, 2000, and filed with the Securities and Exchange Commission on March 13, 2001)
10.1	— Stock Ownership and Registration Rights Agreement dated June 29, 1999 between Union Oil Company of California and the Registrant. (Incorporated by reference to Exhibit 10.2 in the Registrant's Form 8-K Report dated July 19, 1999, and filed with the Securities and Exchange Commission on July 19, 1999)
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10.3	— Canadian Revolving Credit Agreement dated March 20, 2001. (Incorporated by reference to Exhibit 10.3 in the Registrant's Form 10-Q Report for the quarterly period ended March 31, 2001 and filed with the Securities and Exchange Commission on May 14, 2001)
10.4	— Canadian Term Credit Agreement dated March 20, 2001. (Incorporated by reference to Exhibit 10.4 in the Registrant's Form 10-Q Report for the quarterly period ended March 31, 2001 and filed with the Securities and Exchange Commission on May 14, 2001)
10.5	— Credit Agreement dated June 30, 2000, among the Registrant, The Chase Manhattan Bank and the other lenders parties thereto. (Incorporated by reference to Exhibit 10.1 in the Registrant's Form 10-Q Report for the quarterly period ended June 30, 2000, and filed with the Securities and Exchange Commission on August 14, 2000)

10.6 — Credit Agreement, dated as of April 17, 1998, among the Registrant, The Chase Manhattan Bank and the other lenders parties thereto. (Incorporated by reference to Exhibit 10.1 in the Registrant's Form 10-Q for the quarterly period ended March 31, 1998, and filed with the Securities and Exchange Commission on May 14, 1998)

10.7 — First Amendment, dated October 19, 1998, to the Credit Agreement, dated April 17, 1998. (Incorporated by reference to Exhibit 10.1 in the Registrant's Form 10-Q Report for the quarterly period ended September 30, 1998, and filed with the Securities and Exchange Commission on November 13, 1998)

10.8 — Second Amendment and Waiver, dated March 15, 1999, to the Credit Agreement, dated April 17, 1998. (Incorporated by reference to Exhibit 10.7 in the Registrant's Form 10-K Report for the fiscal year ended December 31, 1998 and filed with the Securities and Exchange Commission on March 19, 1999)

10.9 — Third Amendment, dated June 25, 1999, to the Credit Agreement, dated April 17, 1998. (Incorporated by reference to Exhibit 10.1 in the Registrant's Form 10-Q Report for the quarterly period ended June 30, 1999, and filed with the Securities and Exchange Commission on August 13, 1999)

Executive Compensation Plans and Arrangements (Exhibits 10.10 through 10.23):

10.10 — Second Amendment and Restated Employment Agreement dated January 1, 1997, between the Registrant and Donald L. Evans. (Incorporated by reference to Exhibit 10.15 in the Registrant's Form 10-K Report for the fiscal year ended December 31, 1996, and filed with the Securities and Exchange Commission on March 27, 1997)

10.11 — First Amendment to Employment Agreement dated as of July 1, 1998, between the Registrant and Donald L. Evans. (Incorporated by reference to Exhibit 10.3 in the Registrant's Form 10-Q Report for the quarterly period ended June 30, 1998, and filed with the Securities and Exchange Commission on August 10, 1998)

10.12 — Employment Agreement dated May 3, 1999 between the Registrant and James D. Lightner. (Incorporated by reference to Exhibit 10.3 in the Registrant's Form 8-K Report dated July 19, 1999, and filed with the Securities and Exchange Commission on July 19, 1999)

10.13 — The Registrant's Severance Plan dated as of July 1, 1998. (Incorporated by reference to Exhibit 10.2 in the Registrant's Form 10-Q Report for the quarterly period ended June 30, 1998, and filed with the Securities and Exchange Commission on August 12, 1998)

10.14 — First Amendment to Tom Brown, Inc. Severance Plan dated May 10, 2001. (Incorporated by reference to Exhibit 10.5 in the Registrant's Form 10-Q Report for the quarterly period ended March 31, 2001 and filed with the Securities and Exchange Commission on May 14, 2001)

10.15 — Severance Agreement dated as of July 1, 1998, together with a schedule identifying officers of the Registrant who are parties thereto and the multiple of earnings payable to each officer upon termination resulting from certain change in control events. (Incorporated by reference to Exhibit 10.1 in the Registrant's Form 10-Q Report for the quarterly period ended June 30, 1998, and filed with the Securities and Exchange Commission on August 12, 1998)

10.16 — First Amendment to Severance Agreement dated May 10, 2001. (Incorporated by reference to Exhibit 10.8 in the Registrant's Form 10-Q Report for the quarterly period ended March 31, 2001 and filed with the Securities and Exchange Commission on May 14, 2001)

10.17*	— Amended Schedule to Severance Agreement identifying officers and executives of the Registrant who are parties thereto and the multiple of earnings payable to each officer or executive upon termination resulting from certain change in control events
10.18	— Deferred Compensation Plan dated March 1, 2001. (Incorporated by reference to Exhibit 10.22 in the Registrant's Form 10-K Report for the fiscal year ended December 31, 2000, and filed with the Securities and Exchange Commission on March 13, 2001)
10.19	— 1999 Long-Term Incentive Plan effective as of February 17, 1999. (Incorporated by reference to Exhibit 10.11 in the Registrant's Form 10-K Report for the fiscal year ended December 31, 1999, and filed with the Securities and Exchange Commission on March 22, 2000)
10.20	— Amendment to Tom Brown, Inc. 1999 Long-Term Incentive Plan dated May 10, 2001. (Incorporated by reference to Exhibit 10.6 in the Registrant's Form 10-Q Report for the quarterly period ended March 31, 2001 and filed with the Securities and Exchange Commission on May 14, 2001)
10.21	— Amended and Restated 1993 Stock Option Plan. (Incorporated by reference to Exhibit 10.1 in the Registrant's Form 10-Q Report for the quarterly period ended March 31, 2001 and filed with the Securities and Exchange Commission on May 14, 2001)
10.22	— Amendment to Tom Brown, Inc. Amended and Restated 1993 Stock Option Plan dated May 10, 2001. (Incorporated by reference to Exhibit 10.7 in the Registrant's Form 10-Q Report for the quarterly period ended March 31, 2001 and filed with the Securities and Exchange Commission on May 14, 2001)
10.23	— 1989 Stock Option Plan. (Incorporated by reference to Exhibit 10.17 in the Registrant's Form S-1 Registration Statement dated February 14, 1990, and filed with the Securities and Exchange Commission on February 13, 1990)
21.1*	— Subsidiaries of the Registrant
23.1*	— Consent of Arthur Andersen LLP
23.3*	— Consent of Ryder Scott Company

* Filed herewith

(4) Reports on Form 8-K:

Form 8-K Item 7. 2001 Financial Model Estimates filed on November 8, 2001.

Form 8-K Item 7. 2002 Financial Model Estimates filed on February 28, 2002.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TOM BROWN, INC.

By /s/ JAMES B. WALLACE
James B. Wallace
Chairman of the Board of Directors

Date: March 19, 2002

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ JAMES B. WALLACE James B. Wallace	Chairman of the Board	March 19, 2002
/s/ JAMES D. LIGHTNER James D. Lightner	President, Chief Executive Officer and Director	March 19, 2002
/s/ DANIEL G. BLANCHARD Daniel G. Blanchard	Executive Vice President, Chief Financial Officer and Treasurer	March 19, 2002
/s/ RICHARD L. SATRE Richard L. Satre	Controller	March 19, 2002
/s/ THOMAS C. BROWN Thomas C. Brown	Director	March 19, 2002
/s/ DAVID M. CARMICHAEL David M. Carmichael	Director	March 19, 2002
/s/ HENRY GROPPE Henry Groppe	Director	March 19, 2002
/s/ EDWARD W. LEBARON, JR. Edward S. LeBaron, Jr.	Director	March 19, 2002
/s/ ROBERT H. WHILDEN, JR. Robert H. Whilden, Jr.	Director	March 19, 2002
/s/ WAYNE W. MURDY Wayne W. Murdy	Director	March 19, 2002

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* Filed herewith

ANNUAL MEETING

The 2001 annual meeting of Tom Brown, Inc. shareholders will be held May 9, 2002 at 9 a.m. Mountain Time, at the Hyatt Regency Hotel, 1750 Welton Street, Denver, CO. The usual notice and proxy statements will be mailed to all registered shareholders in advance of the meeting.

EXECUTIVE OFFICES

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Denver, Colorado 80202-3918
303-260-5000
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Website: www.tombrown.com

COMMON STOCK

Listed as "TMBR" on the NASDAQ National Market

TRANSFER AGENT

EquiServe Trust Company, N.A.
150 Royall Street
Canton, MA 02021
781-575-3100
Website: www.equiserve.com

Communication concerning the transfer of shares, lost certificates, duplicate mailings or change of address should be directed to the transfer agent.

TOM BROWN, INC.

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